10 CFR 54

Progress Energy

Serial: RNP-RA/03-0074

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United States Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261/LICENSE NO. DPR-23

SUPPLEMENTAL INFORMATION REGARDING LICENSE RENEWAL APPLICATION

Ladies and Gentlemen:

By letter dated June 14, 2002, Carolina Power & Light (CP&L) Company submitted an application for the renewal of the Operating License for the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, also referred to as the Robinson Nuclear Plant (RNP).

By letter dated February 11, 2003, with supplement dated February 21, 2003, the NRC provided a request for additional information (RAI) regarding the technical information included in the application. CP&L, now doing business as Progress Energy Carolinas, Inc., provided a response to the RAIs by letter dated April 28, 2003. This letter provides supplemental information relating to the RAIs in the form of revised responses. The revised responses involve additions, clarifications, and revisions to the previous RAI responses.

Attachment I provides an Affirmation in accordance with 10 CFR 50.30(b).

Attachment II identifies changes to license renewal commitments resulting from the supplemental RAI information. These represent changes to the commitments listed in Attachment II of the RAI response letter dated April 28, 2003. Four of the commitments have been modified to reflect changes required by the revised responses to the RAIs in this letter.

Attachment III provides the revised RNP responses to the RAIs.

If you have any questions concerning this matter, please contact me.

Sincerely,

C. T. Baucom
Supervisor – Licensing/Regulatory Programs

Progress Energy Carolinas, Inc.
Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

A091

Attachments:

I. Affirmation
II. Revised Robinson Nuclear Plant License Renewal Commitments
III. Supplemental Information To The Response To Request For Additional Information Regarding Application For Renewal Of Operating License

MHF/mhf

c: Mr. T. P. O'Kelley, Director, Bureau of Radiological Health (SC) (w/o Attachments)
Mr. L. A. Reyes, NRC, Region II (w/Attachments)
Mr. C. P. Patel, NRC, NRR (w/o Attachments)
NRC Resident Inspectors, HBRSEP (w/o Attachments)
Mr. S. K. Mitra, NRC, NRR (w/Attachments)
Attorney General (SC) (w/o Attachments)
Mr. R. M. Gandy, Division of Radioactive Waste Management (SC)
(w/o Attachments)

AFFIRMATION

The information contained in letter RNP-RA/03-0074 is true and correct to the best of my information, knowledge and belief; and the sources of my information are officers, employees, contractors, and agents of Progress Energy Carolinas, Inc. I declare under penalty of perjury that the foregoing is true and correct.

Executed on: 13 June 2003

J. W. Moyer
J. W. Moyer
Vice President, HBRSEP, Unit No. 2

Revised Robinson Nuclear Plant License Renewal Commitments

(The following table lists the commitments that have changed based on the information provided in Attachment III)

Item	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Location	Frequency	Source
27.	To enhance the Dam Inspection Program, the system monitoring administrative controls will be revised to: (1) identify the "Recommended Guidelines for Safety Inspection of Dams" as the required management program document for the dam, (2) require the responsible system engineer to review the inspection report and initiate corrective actions for any unacceptable attributes, (3) include "Recommended Guidelines for Safety Inspections of Dams" as the applicable inspection guidance in the inspection procedure for RNP, (4) inspect above grade accessible concrete, and (5) inspect submerged spillway concrete on a frequency not to exceed (10) ten years. Revised commitment	A.3.1.24	Prior to the period of extended operation	LR Application Appendix B, Section B.3.16 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of Operating License, dated October 23, 2002 RAI B.3.14-1

Revised Robinson Nuclear Plant License Renewal Commitments

Item	Commitment	UFSAR Supplement Location	Frequency	Source
31.	The Nickel-Alloy Nozzles and Penetrations Program is a new program that will incorporate the following: (1) evaluations of indications will be performed under the ASME Boiler & Pressure Vessel Code, Section XI program, (2) corrective actions for augmented inspections will be performed in accordance with repair and replacement procedures equivalent to those requirements in ASME Boiler & Pressure Vessel Code, Section XI, (3) RNP will maintain its involvement in industry initiatives and will implement any actions, unless impracticable, that are agreed upon between the NRC and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the Vessel Head Penetration (VHP) nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP upper reactor vessel head during the extended period of operation, and (4) RNP will submit, for review and approval, its inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from the applicant's participation in industry initiatives, prior to July 31, 2009. Revised commitment	A.3.1.28	As noted in the commitment	LR Application Appendix B, Section B.4.1 RAI B.4.1-1
41.	Credit is taken for existing Environmental Qualification (EQ) of Electric Equipment activities. EQ is an ongoing program. EQ packages are undergoing revision to incorporate increased radiation values resulting from power uprate and will be updated prior to the end of the current license term. Revised commitment	A.3.1.38	As noted in the commitment	RAI 4.4-2 RAI 4.4.1-2

Revised Robinson Nuclear Plant License Renewal Commitments

Item	Commitment	UFSAR Supplement Location	Frequency	Source
43.	<u>TLAA – Metal Fatigue</u>. Based upon the most recent fatigue analysis performed to date for the three Auxiliary Feedwater (AFW)-to-Feedwater (FW) line connections downstream of the steam-driven pump, transient limits have been reduced in the RNP Fatigue Monitoring Program. These reduced limits are based upon inputs used in the analysis, and are more conservative than the original limits. The reduced limits will remain in effect until the connections are further analyzed, repaired, or replaced to assure the connections remain within their design basis through the period of extended operation. Based upon the fatigue analyses performed to consider environmentally assisted fatigue, the load/unload transient limit has been reduced in the RNP Fatigue Monitoring Program. The reduced limits are based upon inputs used in the analyses, and will remain in effect permanently unless the components are reanalyzed. The reduced limit is not expected to be approached through the period of extended operation, because the original limit was established at a high value to account for load following, which is not necessary at RNP. Further action is required for management of environmental fatigue of the surge line for the period of extended operation. Therefore, fatigue of the surge line will be managed using one or more of the following options: 1. Further refinement of the fatigue analyses to maintain the EAF-adjusted CUF below 1.0. 2. Repair of the affected locations. 3. Replacement of the affected locations. 4. Manage the effects of fatigue through the use of an augmented inservice inspection program that has been reviewed and approved by the NRC. This includes periodic surface and volumetric examinations of the limiting locations at inspection intervals to be determined by a method accepted by the NRC. If this option is selected, the scope, qualification, method, and frequency will be provided to the NRC for review and approval prior to the period of extended operation. Revised commitment	A.3.2.2	As noted in the commitment	LR Application, Section 4.3 RAI 4.3-2 RAI 4.3-7 RAI 4.3-10

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

SUPPLEMENTAL INFORMATION TO THE RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING APPLICATION FOR RENEWAL OF OPERATING LICENSE

Table of Contents

ACRONYMS AND ABBREVIATIONS

AAC	Alternate AC
AC	Alternating Current
ACI	American Concrete Institute
AEC	Atomic Energy Commission
AFW	Auxiliary Feedwater
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
ALARA	As Low As Reasonably Achievable
AMP	Aging Management Program
AMR	Aging Management Review
AMSAC	ATWS Mitigation System Actuation Circuitry
ANL	Argonne National Laboratory
ANSI	American National Standards Institute
API	American Petroleum Institute
ASA	American Standards Association
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transient Without Scram
AVT	All Volatile Treatment
AWS	American Welding Society
AWWA	American Water Works Association
B&PV	Boiler And Pressure Vessel
BIT	Boron Injection Tank
CASS	Cast Austenitic Stainless Steel
CCW	Component Cooling Water
CFR	Code Of Federal Regulations
CLB	Current Licensing Basis
CMAA	Crane Manufacturers Association Of America, Inc.
CP&L	Carolina Power & Light Company
CRDM	Control Rod Drive Mechanism
CS	Carbon Steel
CSS	Containment Spray System
CST	Condensate Storage Tank
CUF	Cumulative Utilization Factor
CV	Containment Vessel
CVCS	Chemical And Volume Control System
DBA	Design Basis Accident
DBD	Design Basis Document
DBE	Design Basis Earthquake
DG	Diesel Generator
DS	Dedicated Shutdown

ACRONYMS AND ABBREVIATIONS

DSDG	Dedicated Shutdown Diesel Generator
E&C	Environment and Chemistry
EAF	Environmentally Assisted Fatigue
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EFPY	Effective Full-Power Years
EHC	Electro-Hydraulic Control
EJMA	Expansion Joint Manufacturers Association
EMA	Equivalent Margins Analysis
EOCI	Electric Overhead Crane Institute
EOF	Emergency Operations Facility
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQDP	Environmental Qualification Data Package
ER	Environmental Report
ESF	Engineered Safety Features
FHB	Fuel Handling Building
FO	Fuel Oil
FSAR	Final Safety Analysis Report
FW	Feedwater
GALL	Generic Aging Lessons Learned (GALL) Report, NUREG - 1801
GDC	General Design Criteria
GL	Generic Letter
GSI	Generic Safety Issue
HAD	Heat Actuated Device
HEPA	High-Efficiency Particulate Air Filters
HELB	High Energy Line Break
HPSI	High Pressure Safety Injection
HVAC	Heating, Ventilating, and Air Conditioning
I&C	Instrumentation and Control
IA	Instrument Air
IASCC	Irradiation Assisted Stress Corrosion Cracking
IEEE	Institute Of Electrical and Electronic Engineers
ILRT	Integrated Leak Rate Test (Containment Type A Test)
IN	Information Notice
INPO	Institute Of Nuclear Power Operations
IPA	Integrated Plant Assessment
IPCEA	Insulated Power Cable Engineers Association
ISFSI	Independent Spent Fuel Storage Installation
ISI	In-Service Inspection
IST	In-Service Testing
IVSW	Isolation Valve Seal Water
LAQT	Low Alloy Quenched and Tempered

ACRONYMS AND ABBREVIATIONS

LBB	Leak-Before-Break
LOCA	Loss-of-Coolant Accident
LR	License Renewal
LRA	License Renewal Application
MCC	Motor Control Center
MDAFW Pump	Motor-Driven Auxiliary Feedwater Pump
MIC	Microbiologically Induced Corrosion
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NACE	National Association of Corrosion Engineers
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufacturer's Association
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
OE	Operating Experience
PAP	Personnel Access Portal
pH	Concentration of Hydrogen Ions
PM	Preventive Maintenance
PORV	Power-Operated Relief Valve
PPS	Penetration Pressurization System
PRT	Pressurizer Relief Tank
PSAR	Preliminary Safety Analysis Report
P-T	Pressure-Temperature
PTS	Pressurized Thermal Shock
PVC	Polyvinyl Chloride
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
PWST	Primary Water Storage Tank
PZR	Pressurizer
QA	Quality Assurance
QC	Quality Control
RAB	Reactor Auxiliary Building
RAI	Request for Additional Information
RCDT	Reactor Coolant Drain Tank
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RG	Regulatory Guide
RH	Relative Humidity
RHR	Residual Heat Removal
RMS	Radiation Monitoring System
RNP	H. B. Robinson Steam Electric Plant, Unit No. 2, or Robinson

ACRONYMS AND ABBREVIATIONS

	Nuclear Plant
RO	Refueling Outage
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RT_{NDT}	Reference Temperature, Nil-Ductility Transition
RT_{PTS}	Reference Temperature, Pressurized Thermal Shock
RTS	Reactor Trip System
RV	Reactor Vessel
RWST	Refueling Water Storage Tank
SAR	Safety Analysis Report
SBO	Station Blackout
SCs	Structures and Components
SCC	Stress Corrosion Cracking
SDAFW Pump	Steam-Driven Auxiliary Feedwater Pump
SEN	Significant Event Notification
SER	Safety Evaluation Report
SFP	Spent Fuel Pit
SG, S/G	Steam Generator
SI	Safety Injection
SIT	Structural Integrity Test
SOER	Significant Operating Event Report
SOV	Solenoid Operated Valve
SR	Silicone Rubber
SRP	Standard Review Plan
SS	Stainless Steel
SSCs	Systems, Structures, and Components
SSE	Safe Shutdown Earthquake
SFPCS	Spent Fuel Pit Cooling System
SWS	Service Water System
TAP	Task Action Plan
TEMA	Tubular Exchanger Manufacturer's Association
TGSCC	Transgranular Stress Corrosion Cracking
TID	Total Integrated Dose
TLAA	Time-Limited Aging Analysis
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
USAS	United States Of America Standards
USE	Upper Shelf Energy
UT	Ultrasonic Test
VCT	Volume Control Tank
WCAP	Westinghouse Commercial Atomic Power
WDS	Waste Disposal System

ACRONYMS AND ABBREVIATIONS

VHP	Vessel Head Penetration
WOG	Westinghouse Owner's Group

Clarifications provided below, designated A through Q, are in response to questions provided via e-mail from Mr. S. K. Mitra, NRC, to Mr. Roger Stewart, Progress Energy Carolinas, Inc., also known as Carolina Power & Light Company.

RAI Clarification A (RAI B.3.8-1, RAI B.3.12-1):

The staff has questions on the applicant's draft responses to RAI B.3.8 and B.3.12 regarding buried piping and tanks surveillance program and inspection program, respectively.

(1) The applicant stated that service water and fire protection systems also have buried piping, in addition to the fuel oil piping (Table 3.3-1 Item 17). However, in the draft response to B.3.8-D1 (buried piping surveillance program) and B.3.12-D1, it seems that the buried pipes in the service water system and fire protection system are not considered in either the buried piping surveillance program or buried piping inspection program. The only buried piping covered in these two AMPs is the fuel oil piping. The staff believes that all buried piping considered for the license renewal application should be covered either in the surveillance program or inspection program or both. Clarify why the service water and fire protection system piping are not considered by these 2 AMPs.

(2) The applicant needs to discuss how they intend to inspect or conduct surveillance on the service water and fire protection system buried piping, if these piping are not covered in the buried piping surveillance program or inspection program. Identification of water on the soil surface above the underground piping is not a sufficient method of surveillance because it would be after the effect.

(3) Confirm that the buried piping covered in the license renewal application consists of the fuel oil piping, service water system piping, and fire protection system piping.

(4) Identify those buried piping that are not covered in the license renewal and clarify why they are not considered in the scope of review.

Supplemental RAI Response A:

(1) Buried pipes within the evaluation boundaries for the service water system and fire protection system are included in the buried piping inspection program.

The RNP Responses to the Draft RAI B.3.8-D1 and RAI B.3.8-1 state that the buried fuel oil piping is contained within the buried piping surveillance program. The cathodic protection system, which is the subject of the buried piping surveillance program, is only associated with fuel oil piping. The RNP cathodic protection system does not protect buried pipes in the service water system and fire protection system; therefore, they are not mentioned in these responses to Draft RAI B.3.8-D1 and RAI B.3.8-1. Only the

activity for inspection of coatings on the buried fuel oil piping is combined with the inspections performed as part of the buried piping inspection program.

The RNP Responses to the Draft RAI B.3.12-D1 and RAI B.3.12-1 are related to the buried piping inspection program and address buried piping in the service water and fire protection systems as follows:

The service water system buried pipes within the scope of the buried piping inspection program consist of the highlighted pipes on the evaluation boundary drawing G-190199LR, Sheet 2, from intake structure through the 30 inch north and south service water supply headers. The underground portion of the north service water header rises above the ground outside the south end of the Radwaste Building as shown on Sheet 9 (G-4). The south service water header rises above ground inside the component cooling water heat exchanger room in the Reactor Auxiliary Building as shown on Sheet 10 (B-1). The service water return included in the buried piping inspection program is a small segment outside the component cooling water heat exchanger room that connects to the underground circulating water system return from the condenser catch basin as shown on Sheet 1, (F-8).

The fire protection system buried pipes within the scope of the buried piping inspection program consist of highlighted 4 inch, 6 inch, 8 inch, 10 inch, and 12 inch pipes on the evaluation boundary drawing HBR2-8255LR, Sheets 1, 2 and 6. The buried piping segments typically include piping components originating at the intake and are shown as piping outside of buildings. The NFPA 24 class breaks designate the underground piping.

(2) Under detection of aging mechanism the GALL program states:

> "Periodic inspection of susceptible locations to confirm that coating and wrapping are intact is an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. Buried piping and tanks are inspected when they are excavated during maintenance. The inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. However, because the inspection frequency is plant specific and also depends on the plant operating experience, the applicant's proposed inspection frequency is to be further evaluated for the extended period of operation."

With regard to detection of aging mechanisms and inspections, the activities forming the RNP program, including evaluation of inspection frequency, are consistent with the GALL program. RNP will inspect coatings whenever buried piping is excavated, and not just for maintenance as stated in the GALL program. LRA section B.3.12 discusses the site specific history of leakage in buried piping for the piping covered under this program. There was no leakage identified for the fire protection system. The leakages identified in the service water piping were associated with a specific segment of the

underground north service water header. This segment of piping is no longer buried. Those instances of leakages were related to installation activities due to rerouting of the buried portion due to erection of the Radwaste Building. It was not due to a generalized degradation of pipe coating. The evaluations noted that the resistivity of the soil at RNP is very high, which minimizes the potential for corrosion. Based on these facts supported by site experience, RNP concludes that no specific schedules for inspections are warranted for the service water and fire protection underground piping.

(3) See Response to clarification item (1) above.

(4) The buried pipes that are not covered in the license renewal are those buried pipes that are not highlighted on the associated evaluation boundary drawings.

There are no service water system buried pipes outside the scope of the buried piping inspection program. The highlighted 126" underground, concrete condenser circulating water system return to the discharge basin shown on Sheet 1 (F-8) of G-190199LR was determined to have no potential aging mechanisms requiring management.

RAI Clarification B (RAI 2.3.3.15-5):

The RAI responses are reasonable except for RAI 2.3.3.15-5. The applicant states that the boundaries are 'viable isolation points', but it is not clear from the response that there will be no problem if leaks were to occur in the unmanaged portions. For example, one pipe feeds to the fuel pool. If the pipe were to leak to the fuel pool, this could cause dilution of the fuel pool, or overflow of the pool. This would be significant.

The fire protection system is not designed to identify the specific location of leaks, although a leak will be detected by the actuation of the fire pump, it won't be clear to the operations staff until a plant walkdown occurs where the leak exists.

I feel that the solution is to include the piping all the way up to the isolation valve in scope. If RNP chooses not to do this, a much more significant justification than is currently provided in the RAI will be needed.

Supplemental RAI Response B:

RNP has performed additional reviews to identify potential vulnerabilities associated with the boundaries identified in this RAI. The results of this review are as follows:

Fire water supply to spent fuel pit area: FP-71 is an open valve on the fire water system supply to the spent fuel pit area. This piping will be conservatively included in License Renewal scope up to and including fire hose station FH-104.

Fire water supply to transformer sprinkler systems: FP-54, FP-56 and FP-58 are open valves on the fire water system supply piping to the transformer sprinkler systems. This piping does not represent a spatial interaction hazard, but the NRC has expressed concern that undetected leakage in downstream piping could degrade fire protection system capability. To address this concern, the scoping boundary will be expanded up to and including the downstream deluge valve.

Fire water supply to site buildings: The buildings in question contain no safety-related components and are outside the scope of 10 CFR 50.48. The fire water piping to these buildings does not represent a spatial interaction hazard, but the NRC has expressed concern that undetected leakage could degrade fire protection system capability. To address this concern, License Renewal scoping boundaries will be expanded to include the piping beyond the open isolation valves listed in the table included in RAI 2.3.3.15-5 up to the penetration in the building or structure downstream. RNP considers this response to sufficient based on the following considerations:

(1) It includes the relatively large bore, buried piping up to the building in scope. Smaller bore piping past branch connections inside the building are unlikely to develop leaks that could significantly degrade fire water system capability.

(2) While the piping inside the buildings is not in scope, these buildings and the area around them are subject to ongoing observation as a result of personnel traffic, operator rounds, and security tours. It is improbable that a leak of significant volume could develop and remain undetected for an appreciable time in these spaces.

(3) System design ensures that any significant leakage occurring in the portion of the fire protection system outside the boundaries established for 10 CFR 50.48 compliance would be readily detected and resolved. System pressure in the RNP fire water system is normally maintained by a fire protection jockey pump. Even a small system demand would cause a sufficient drop in pressure to initiate operation of the 2500 gpm motor driven fire water pump, which has remote indication on the fire protection console in the plant control room. Plant procedures directing the response to this annunciation identify the potential for system leakage and direct immediate investigation and appropriate follow-up action. Isolation valves are located at strategic locations to permit partial isolation of the fire water loop without loss of service to other sections of the system.

(4) System design does not uniformly include closed isolation devices in these buildings prior to endpoint devices, such as hose stations or sprinklers. Inclusion of the entire water-based fire suppression system inside these buildings within the License Renewal scope is not warranted.

RAI Clarification C:

The concerns relate to the responses to RAIs 2.3.3.8-1, 2.3.3.8-2, and 2.3.3.9-1. For RAI 2.3.3.8-1, the response does not provide sufficient justification to support the applicant's contention that the dam failure described in Sections 9 and 10 of the SAR is not a design basis event. For RAI 2.3.3.8-2, the reference to GL 84-04 allows the applicant to credit leak-before-break in protecting CCW system piping from rupture of large-diameter RCS piping, but ruptures of SI, PZR spray, and S/G blowdown piping are also credible initiators of missiles capable of damaging CCW piping. Finally, for RAI 2.3.3.9-1, Amendment 156 credits the redundant SFP cooling pump and makeup from the RWST in preventing a substantial loss of coolant inventory, which is a design basis event.

C.1 Response related to RAI 2.3.3.8-1

Based on discussions with the NRC staff, additional information has been identified regarding the origin of the function of the deepwell pumps to supply water to the auxiliary feedwater system. The system drawing in the original FSAR shows a connection from the deepwell pumps to the condensate storage tank. Subsequently, in a letter from the Atomic Energy Commission (letter from P. A. Morris, AEC, to P. S. Colby, CP&L: Request for Additional Information on Request for Provisional Operating License, dated November 5, 1969), several questions regarding design features were provided. Question 8-1C and Question 9-1 relate to using the deepwell pumps to supply auxiliary feedwater. Question 8-1C stated:

> "Describe the equipment actuation sequence and electrical load schedule required to shut the plant down to hot standby and cold conditions for each of the following situations:
>
> Failure of Lake Robinson Dam. Indicate which loads are not directly on the emergency buses for those conditions which require emergency power. Discuss the critical times in the actuation sequence in which operator action is required to prevent equipment damage."

Question 9-1 stated:

> "The deep well pumps are considered as a source of cooling water in the event of a dam failure. State the minimum flow rate and capacity available from the well and the basis for these values."

The responses to these questions were incorporated into the FSAR in early 1970. The response to Question 8-1C indicated that the deepwell pumps would be used as a source of auxiliary feedwater after the condensate storage tank reached a low level, and the response to Question 9-1 indicated that the deepwell pumps could provide sufficient

cooling water flow for steam generator makeup. However, the response to Question 8-1C also stated "[t]he Lake Robinson Dam has been evaluated as having ample margin of safety to withstand seismic forces well in excess of the maximum hypothetical earthquake of 0.2 g. Therefore specific design features have not been provided to prevent equipment damage for this type of accident." This statement, together with the request of Question 9-1 to define the basis for the flow rate and capacity of the deepwell pumps, indicates that the deepwell pumps were not originally designed to provide the auxiliary feedwater function. Furthermore, the original FSAR indicates that the only backup supply for the auxiliary feedwater system is the service water system, which provides water from Lake Robinson.

Based on the above and the original response to RAI 2.3.3.8-1, the following conclusions have been drawn:

- The dam is credited for maintaining the reservoir which is the UHS for RNP.
- The dam has been seismically analyzed and determined to be capable of maintaining its function during and following an earthquake.
- The dam is in scope of LR and has an AMP.
- The original design basis for the deepwell pumps did not include providing cooling water for the hypothetical failure of the dam.
- Failure of the dam is not a design basis event; therefore, the function provided by the deepwell pumps is not an intended function.

C.2 Response related to RAI 2.3.3.8-2

In addition to the information in the RAI Response, the following details are provided:

The review of potential pipe break effects inside containment on CCW lines included consideration of ruptures of other high energy piping, as well as the large-diameter RCS piping. Specifically, ruptures and impingement jets of RCS branch lines and other systems were considered. Westinghouse (the RNP NSSS Designer) provided the hydraulic requirements and Ebasco (the RNP Architect/Engineer) designed the piping and supports at RNP. Ebasco conducted a generic study and concluded that the effects of jet forces from ruptured Ebasco-designed piping would not result in the loss of structural integrity of other Ebasco-designed piping and support systems, such as the CCW system. This evaluation considered RCS branch lines and other high energy systems in containment. In addition, non-piping missile sources were considered (i.e., reactor coolant pumps and valves). The conclusions of the evaluation were that the CCW lines are protected from the effects of postulated ruptures of high energy systems, and the CCW system inside containment is considered to be a closed system and "missile protected" for the purposes of containment isolation.

RNP documentation regarding the effects of high energy pipe ruptures on the CCW system were enhanced in response to a finding from an NRC Design Inspection of RNP

conducted from April 7 to May 23, 1997. Refer to Unresolved Item 50-261/97-201-03, which was closed by NRC Inspection Report dated February 6, 1998.

C.3 Response related to RAI 2.3.3.9-1

The NRC request regarding the SFP states: "...for RAI 2.3.3.9-1, Amendment 156 credits the redundant SFP cooling pump and makeup from the RWST in preventing a substantial loss of coolant inventory, which is a design basis event."

Amendment No. 156 to the Technical Specifications and the associated SER discuss criticality aspects of the SFP and New Fuel Racks as reported in EMF-94-113, "H. B. Robinson New and Spent Fuel Criticality Analysis." Neither document explicitly addresses the SFP cooling pump and makeup from the RWST.

Amendment No. 156 to the Technical Specifications references Section 9.1 of the UFSAR. The information associated with this amendment is found in Section 9.1.1 and 9.1.2 for the discussion on new fuel storage and SFP storage, respectively. The RWST connection that is being referred to in the NRC request is closely related to Section 9.1.3, spent fuel pool cooling and cleanup system. Subsection 9.1.3 does not apply to or support Amendment No. 156.

UFSAR section 9.1.3.3.2, Pool Water Makeup Capability, states:

"The makeup water requirement due to boiling in the fuel pool following a complete loss of cooling after a full core offload would be less than 42 gpm."

"The SFP large level makeup water source is the refueling water storage tank via the refueling water purification pump. This path has a capacity of 100 gpm, which is more than adequate to replace the water lost."

The above discussion does not refer to a design basis event. The path being described is the RWST connection to the suction of the refueling water purification pump (not the redundant SFP cooling pumps). It is a discussion showing that if the SFP were to boil, then there would be adequate capability for makeup until cooling is restored. The refueling water purification pump, associated filters, and the demineralizer are non-safety related equipment. This engineering design basis is not associated with a safety related function; rather, it is associated with the clean-up requirements of the spent fuel pool and the RWST. As noted in the UFSAR, the connection to the RWST is another source of water for make-up to the SFP that could be used if needed. If this were a design basis event as defined in 10 CFR 50.49(b)(ii), then it would imply that the consequences of boiling in the SFP meet the criteria in 10 CFR 50.49(b)(1)(i)(c), which relate to potential offsite exposures. For this to occur, the coolant inventory in the SFP would have to be depleted below the level of the spent fuel in the SFP. Without any makeup, there is adequate time to restore a source of cooling, or makeup, to the pool.

Due to the time available to restore cooling, or make-up, the consequences of water boiling in the SFP, although undesirable, does not rise to the level of an intended function as defined in 10 CFR 54.4(a)(1).

Although the sources of make-up to the SFP are not safety related (including the refueling water purification pump and the SFP piping connected to the RWST isolation valve), the refueling water purification pump and its immediate suction and discharge piping are located in the RAB near safety related equipment and have been included in the scope of license renewal based on 10 CFR 54.4(a)(2). The potential aging effects for this equipment will be managed throughout the period of extended operation. In addition, the clarification to RNP Response RAI 2.3.3.15-5 addresses the fire water supply to spent fuel pit area. Fire protection valve FP-71 is an open valve on the fire water system supply to the spent fuel pit area. The subject piping will be conservatively included in license renewal scope up to, and including, Fire Hose FH-104. Therefore, the potential aging effects for this equipment will be managed throughout the period of extended operation.

RAI Clarification D (RAI 3.5.1-19):

Open item related to response to RAI 3.5.1-19:

a. Please provide a summary of the technical evaluation performed that concludes that potential degradation in the inaccessible areas as indicated by the inspection in accessible areas is acceptable until the scheduled one-time inspection in 2005. (This can be verified during AMR inspection).

b. The corrective action related to liner plate corrosion: The applicant states that "identified corrosion will be prepared, recoated, and new moisture barrier installed." Without knowing the extent of corrosion, how has the applicant decided that just recoating of the corroded areas would suffice. The corrective action should include the techniques required to bring the liner to its design thickness, e.g., weld overlays or coring the degraded areas and replacing with new compatible liner plate. Please discuss the corrective actions in terms of the extent of liner degradation.

In RAIs related to the review of Section B.3.13 of the LRA, I had indicated an item that should be included in AMR inspection. I am keeping the item hanging in my DSER until the findings in the associated inspection report. The Item is:

II B3.13-1 Confirm the reasonableness of the containment degradation accepted without repairs or corrective actions. ------------Inspection Item during AMP inspection.

Supplemental RAI Response D:

Part a. and Inspection Item II B3.13-1 are to be verified during the Aging Management Review inspection.

Part b. is addressed in a revised response to RAI 3.5.1-19 provided below.

The RNP letter from B.L. Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0125: "Submittal of 90 Day Inservice Inspection Summary Report," August 10, 2001, addresses the conclusions stated in the LRA.

Specifically, the existing condition of the containment liner (behind the moisture barrier), and the moisture barrier, was determined to be acceptable based on visual examinations.

These visual examinations of the containment liner, behind the removed moisture barrier, determined that the corrosion observed did not impact the structural integrity or leak tightness of the containment. This examination did not include six areas that were either blocked by permanent structural features, or in locations not available due to

ALARA considerations. The liner plate areas with identified corrosion were prepared, recoated, and new moisture barrier installed. The six areas that were either blocked by permanent structural features, or in locations not available due to ALARA considerations, were considered to have the same environmental conditions as the areas that were examined. A worst case corrosion rate, as discussed in the RNP Response to RAI 3.5.1-7, was applied to the liner plate behind the moisture barrier. This resulted in the liner plate conservatively meeting the liner plate design thickness until 2005.

In the six areas where the moisture barrier was not replaced, the moisture barrier material was assumed to be degraded. Engineering determined that degradation of the moisture barrier material in these six areas would not result in unacceptable degradation of the containment liner below the minimum design thickness. This was based on the successful examination and evaluation of the liner plate above the moisture barrier, which was determined to be acceptable for continued service until 2005, as discussed above.

The inspection to be performed under the One-Time Inspection Program was determined to be sufficient to monitor the condition of the containment liner behind the insulation and the moisture barrier during the extended period of operation.

Liner plate areas (behind the ¾" by ¾" moisture barrier) will be visually examined (VT-3) for corrosion. At any degraded areas, the degradation is characterized to identify any reduction in liner plate thickness, and compared to the minimum liner design thickness. If the actual thickness is less than the minimum design thickness, appropriate repair methods will be implemented which meet the requirements of the ASME Code, Section XI, Subsection IWE, "Requirements for Class MC and Metallic Liner of Class CC Components of Light-Water Cooled Plants." Repair techniques will be specified by the Robinson Engineering Section, and could involve base metal restoration by welding, removal/replacement of sections of plate, or other techniques allowed by Code. After the liner plate thickness is determined to meet the minimum design thickness requirements, the liner plate surface will be prepared, recoated, and new moisture barrier installed. No additional examinations are planned beyond those required by the ASME Code, Subsection IWE Program.

In accordance with LRA Table 3.5-1, Items 6 and 12, the existing ASME Code, Subsection IWE Program, is committed to for the extended period of operation, and the one-time inspection will be completed prior to 2005.

<u>RAI Clarification E (RAI 4.1-1):</u>

The applicant listed the TLAAs applicable to RNP in Table 4.1-1 of the LRA. Tables 4.1-2 and 4.1-3 in NUREG-1800 identify potential TLAAs determined from the review of other license renewal applications. In RAI 4.1-1 the staff requested that the applicant discuss:

1. Whether there are any calculations or analyses at RNP that address the topics listed in Tables 4.1-2 and 4.1-3 of NUREG-1800 and were not included in Table 4.1-1 of the LRA.
2. Discuss how these calculations or analyses were evaluated against the TLAA definition provided in 10 CFR 54.3 if they do exist.

In its RAI response dated April 28, 2003, the applicant indicated that documentation existed for the following topics listed in NUREG-1800 that are applicable to PWR facilities and were not included in Table 4.1-1 of the LRA of RNP are:

1. In service flaw growth analysis of structure stability
2. Metal containment corrosion allowance
3. High energy line break analysis based on cumulative usage factor
4. Reactor vessel low temperature over pressure protection (LTOP) analysis
5. Main steam supply lines to AFW pump
6. RCP flywheel fatigue analysis
7. Reactor vessel internals transient analysis
8. Reactor vessel internals fracture toughness ductility reduction
9. Containment liner plate fatigue analysis

The applicant stated that there are no high energy line break analysis (item 3) for RNP that rely on fatigue cumulative usage factors, such as those in R.G. 1.46, to identify potential postulated break locations. Based on the results of the search for RNP-specific TLAAs, the calculations or analyses that were identified for these generic TLAA categories, include the reactor vessel for LTOP analysis (item 4), the main steam supply lines to AFW pump (item 5), and the RCP flywheel fatigue analysis (item 6).

The analysis of the main steam supply lines to the AFW pump (item 5) is addressed in LRA Subsection 4.3.2. No explicit fatigue analysis of the main steam supply lines to the steam-driven AFW pump has been identified for RNP. Items 4 and 6 were determined to not meet the criterion from 10 CFR 54.3 that the analysis involves time-limited assumptions defined by the current operating term. The RNP LTOP analyses (item 4) have been performed for periods less than the current operating term and are periodically updated. Further discussion on this matter is provided in RNP Response to RAI 4.2.3-1, Part 2. The RCP flywheel fatigue analysis (item 6) has been performed using an operating life of 60 years.

The RAI response does not address the reasons why items 1, 2, 7, 8, and 9, identified in the RAI response, were not included in Table 4.1-1 of the LRA. The staff finds further justifications are required. This is defined as open item 4.1.2-1.

Supplemental RAI Response E:

The RAI Response states:

"In its RAI response dated April 28, 2003, the applicant indicated that documentation existed for the following topics listed in NUREG-1800 that are applicable to PWR facilities and were not included in Table 4.1-1 of the LRA of RNP are:

1. In service flaw growth analysis of structure stability
2. Metal containment corrosion allowance
3. High energy line break analysis based on cumulative usage factor
4. Reactor vessel low temperature over pressure protection (LTOP) analysis
5. Main steam supply lines to AFW pump
6. RCP flywheel fatigue analysis
7. Reactor vessel internals transient analysis
8. Reactor vessel internals fracture toughness ductility reduction
9. Containment liner plate fatigue analysis"

While the RAI response listed all nine of the generic TLAA categories from NUREG-1800, Tables 4.1-2 and 4.1-3, applicable to a PWR, it did not say that RNP-specific documentation existed for these TLAA categories.

The calculations or analyses that were identified by the search for RNP-specific TLAAs are the three listed items (Items 4, 5, and 6 from the above list). The information provided in the remainder of the paragraph addresses only those three TLAAs that are applicable to RNP. The information provided in the response indicates that no other RNP-specific calculations or analyses were found that fit the generic categories identified in NUREG-1800, Tables 4.1-2 and 4.1-3. The last sentence in paragraph three of the response indicates that high energy line break analyses exist for RNP, but they do not rely on cumulative usage factors, therefore item 3 above does not apply.

In summary, RNP-specific calculations or analyses in the NUREG-1800 categories exist only for the three TLAA categories that were identified and evaluated in the provided RAI Response. Therefore, of the nine potential TLAA categories, only categories 4, 5, and 6 above are applicable to RNP.

RAI Clarification F (RAI 2.3.2.5-1):

I need to discuss further with the applicant RAI 2.3.2.5-1. Specifically, as I discussed the last time, when I compare the applicant's response to the rule, I am unable to conclude that the hydrogen control function is not within the scope of license renewal. Although the applicant has clearly provided enough information to demonstrate that 54.4(a)(1) and (a)(3) do not pertain, it is not apparent why (a)(2) does not apply, based on the language in the rule. Although I don't disagree that the applicant has ample time to effect hydrogen control, the rule does not explicitly consider time, only necessity.

In addition, I have a question concerning the applicant's RAI response in light of UFSAR section 6.2.5.2.2. The RAI response states that "There is sufficient time to assure that all components of the recombiner system are operable before the system is required to be placed in operation." However, the UFSAR says that "the majority of the lines cannot be repaired due to the high radiation rates present during post accident conditions." The obvious question then, is what value is having enough time to assure system operability if the dose rates on the majority of these lines would prevent their repair if they are inoperable?

Supplemental RAI Response F:

Other than the safety related containment isolation piping and components, the subject system is comprised of non-safety related, permanently installed piping and components, and the non-safety related external hydrogen recombiner and connecting temporary flexible piping.

The basis for concluding that 10 CFR 54.4(a)(2) does not apply to the external hydrogen recombiner and connecting temporary flexible piping located in the new fuel storage area, is as follows. Because the employment of the external hydrogen recombiner is a long-term, recovery action, the failure of the external hydrogen recombiner is not assumed. This is a valid assumption, because there is adequate time to install and test the recombiner well before it is needed. If testing reveals a problem, there is time to implement repairs and achieve operability of the equipment, or to obtain replacement equipment, prior to the time it is needed. Therefore, the external hydrogen recombiner and connecting temporary flexible piping does not meet the requirements of 10 CFR 54.4(a)(2), because hydrogen control is a long-term, recovery activity and, therefore, failure of the external hydrogen recombiner and connecting temporary flexible piping is not assumed. Additionally, failure of the external hydrogen recombiner and connecting temporary flexible piping in the new fuel storage area does not create a spatial interaction with any safety-related SSC.

The safety related containment isolation components required for containment isolation are already in scope per 10 CFR 54.4 (a)(1). The intervening non-safety related permanently installed piping does not meet any of the failure modes associated with 10 CFR 54.4 (a)(2) piping, and therefore, is not postulated to have a spatial interaction with any safety-related SSCs. However, because the non-safety related, permanently installed piping must not deteriorate such that it loses its piping pressure boundary component function, and due to potentially high radiation rates present during post accident conditions, this piping is considered to be within the license renewal evaluation boundary and subject to aging management.

The post accident hydrogen system is, therefore, considered to be within the license renewal evaluation boundary and subject to aging management because of the need to assure the long-term, recovery function of maintaining a flow path to the hydrogen recombiner. The non-safety related, permanently installed, post accident hydrogen system connecting piping within the RAB will require inclusion in the Boric Acid Corrosion Program to manage aging effects associated with the carbon steel portion of the piping system.

RAI Clarification G (RAI B.4.1-1, RAI 3.1.2.1-4, RAI 3.1.2.1-5):

Clarify the following:

"(4) RNP will submit, for review and approval, the inspection plan for the Nickel-Alloy Nozzles and Penetration Program, since....... implemented from the applicant's participation in industry initiatives prior to July 31, 2009."

Please clarify what follows after the word since....in the above statement.

Please clarify if the UFSAR will be updated again to reflect our RAI prior to our issuance of final SER.

Supplemental RAI Response G:

The response sent in RNP letter RNP-RA/03-0031, dated April 28, 2003, contained a typographical error. The correct supplemental commitment is as follows:

> "(4) RNP will submit, for review and approval, its inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from the applicant's participation in industry initiatives prior to July 31, 2009."

The commitment is also stated in item 33 on page 8 of 12 of Attachment II to RNP letter RNP-RA/03-0031.

The UFSAR update will be as stated in the RNP Response to RAI B.4.1-1.

In a teleconference on May 21, 2003, the NRC expressed concern that the RNP Nickel-Alloy Nozzles and Penetration Program (Subsection B.4.1 in the RNP LRA) may not capture potential changes to the requirements governing inspections of Alloy 600 vessel head penetration nozzles. To address this concern, RNP will commit to implementing actions, as part of the Nickel-Alloy Nozzles and Penetration Program, that are agreed upon between the NRC and the nuclear power industry, to monitor for, detect, evaluate, and correct cracking in the VHP nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP RPV head during the extended period of operation. As such, part (3) of the commitment associated with the Nickel-Alloy Nozzles and Penetration Program will be revised from:

> "(3) RNP will maintain its involvement in industry initiatives (such as the Westinghouse Owners Group (WOG) and the EPRI Materials Reliability Program (MRP)) during the period of extended operation."

to:

> "(3) RNP will maintain its involvement in industry initiatives and will implement any actions, unless impracticable, that are agreed upon between the NRC and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the VHP nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP upper reactor vessel head during the extended period of operation."

RAI Clarification H:

1. In response to RAI 2.5.2-1 the applicant stated that the original RNP electrical AMR already includes an evaluation of phenolic materials. This evaluation shows that for the worst-case environmental service conditions encountered at RNP, the base of the fuse holder will be able to maintain its intended function throughout the period of extended operation. No additional evaluation of phenolic is warranted. This is not consistent with the requirements of ISG-5. Per ISG-5, the insulating material for the fuse holder shall be managed by GALL XI.E1 "Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements."

2. In response to RAI 4.4-2, the applicant provided RNP EQ Program. The Corrective Actions of this program is not consistent GALL element. The corrective action should be in accordance with the requirements of 10 CFR 50, Appendix B.

3. In response to RAI B4.6-1, the applicant stated that as discussed in LRA Subsection 3.6.2.1, the components subject to aging in the electrical penetration assemblies are the materials for the electrical conductors and connections. Since the electrical conductors and connections will be managed by three programs(Non-EQ Insulated Cables and Connections Program, aging Management program for Non-EQ Electrical cables Used in Instrumentation Circuits, and Aging Management Program for Neutron Flux Instrumentation Circuits), the Non-EQ Electrical Penetration assemblies should be managed by all three Programs.

4. In response to RAI B.4.6-2, the applicant stated that the scope of this program includes plant cables of various insulation material types that may be located in adverse localized environment. The Scope of the program should include cables and connections including fuse holders.

5. In response to RAI 4.4.1-2 a), the applicant stated that RNP completed an Appendix K power uprate in 2002 that resulted in an approximately 1.7% increase in power level. However, the response failed to address the effect of power uprate on temperature and radiation values used in EQ calculation.

Supplemental RAI Response H:

H.1 Response related to RAI 2.5.2-1

Although the original RNP electrical AMR has shown that there are no credible aging effects for phenolic materials, fuse holders are considered another type of electrical connection and, thus, are subject to GALL XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements," consistent with ISG-5. Table 2 from RNP's Response to RAI 2.5.2-1 shows the addition of the GALL X1.E1 Program.

H.2 Response related to RAI 4.4-2

The original response has been amended to include the 10 CFR 50, Appendix B, requirements for the Corrective Actions for this program:

Corrective Actions

Corrective actions, including root cause determinations and prevention of recurrence, are done in accordance with the corrective action program, which is implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. Timeliness of corrective action is monitored.

H.3 Response related to RAI B.4.6-1

The following is the original response, followed by the clarification:

As discussed in LRA Subsection 3.6.2.1, the components subject to aging in the electrical penetration assemblies are the materials for the electrical conductors and connections.

The Aging Management Program for Non-EQ Electrical Cables Used in Instrumentation Circuits applies to the non-EQ portions of the high range radiation monitoring circuits, and the Aging Management Program for Neutron Flux Instrumentation Circuits applies to the non-EQ portions of neutron flux instrumentation circuits. The electrical penetrations used for these circuits are in the EQ program and are, therefore, not subject to these license renewal programs.

H.4 Response related to RAI B.4.6-2

Since fuse holders are considered another type of electrical connection and, thus, subject to the GALL XI.E1 Program, RNP's Response to RAI B.4.6-2 has been revised to include electrical connections. The revision to the original RAI Response is provided below.

The Non-EQ Insulated Cables and Connections Aging Management Program is a condition monitoring program designed to provide reasonable assurance that age-related degradation will not inhibit the intended function of insulated cables and connections within the scope of license renewal during the period of extended operation. The scope of this program includes plant cables and connections of various insulation material types (not just PVC) that may be located in an adverse localized environment. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the cable or connection. The aging effects managed are embrittlement, cracking, melting,

discoloration, swelling or surface contamination that could lead to reduced insulation resistance or electrical failure.

H.5 Response related to RAI 4.4.1-2 a)

The RAI response is amended to provide clarification as shown below.

a) RNP completed a new containment accident analysis in 1999 that resulted in the revision of the temperature versus time profile used as a basis for environmental qualification. RNP completed an Appendix K power uprate in 2002 that resulted in an approximate 1.7% increase in power level.

   The Appendix K power uprate resulted in no change to temperature values and a minor change to radiation values. Radiation dose was increased by 1.02 times the current value. When this multiplier was applied to the current dose rates in the containment for the remaining period through the end of the new license term, it was found that the change in dose was minimal and well within the 10% margin typically added to environmentally qualified equipment. Environmental qualification packages are undergoing revision at this time and will be updated prior to the end of the current license term. (Commitment Number 41).

b) The qualification basis for the equipment impacted by the aforementioned changes had sufficient conservatism to maintain existing qualification.

c) Containment temperature and radiation are logged at least daily, and all other EQ areas have operator walkdowns as part of their rounds at least daily while the plant is operating. The temperature and radiation data obtained is representative of the service conditions of EQ equipment and any change in temperature or radiation that could adversely affect qualification would be readily identified.

   RNP UFSAR Chapter 11.5 describes the Process and Effluent Radiation Monitoring System. High radiation activity from these areas is indicated, recorded and alarmed in the control room. Operator walkdowns as part of their daily rounds, Health Physics radiation monitoring (surveys of areas in the Reactor Auxiliary Building at least monthly, and in some cases daily or weekly), and Maintenance and System Engineering personnel provide feedback to Engineering through RNP's Corrective Action Program when changes to the plant environment or EQ equipment are encountered. Any change in temperature or radiation that could adversely affect qualification would be readily identified. RNP plant procedures govern the frequency of surveillances, radiation surveys, and plant walkdowns. The frequencies range from shiftly to each refueling outage.

RAI Clarification I (RAI 4.3-2):

I. Response to RAI 4.3-2

If operating procedures are changed to the extent that the fatigue usage associated with a particular operation is increased beyond that assumed in the most recent fatigue analysis for the component, the affected fatigue analyses would be revised to account for the more severe thermal stress. Therefore, allowable cycles will be less than previously calculated. The acceptance limit would remain that the CUF must be less than 1.0. If there is no need to reduce cycles for the design transient (i.e., the increase *in fatigue usage from the previous analysis does not result in CUF > 1.0), then no* change would be required to the Fatigue Monitoring Program limits. If the number of cycles for the design transient had to be reduced due to lower allowable cycles to obtain a CUF value less than 1.0, this reduced number of cycles would become the new Fatigue Monitoring Program cycle limit.

Supplemental RAI Response I:

RNP agrees with the suggested clarification to the response. The first paragraph of the response to item 3 of RAI 4.3-2 should be revised to read:

> If operating procedures are changed to the extent that the fatigue usage associated with a particular operation is increased beyond that assumed in the most recent fatigue analysis for the component, the affected fatigue analyses would be revised to account for the more severe thermal stress. Therefore, allowable cycles will be less than previously calculated. The acceptance limit would remain that the CUF must be less than 1.0. If there is no need to reduce cycles for the design transient (i.e., the increase in fatigue usage from the previous analysis does not result in CUF > 1.0), then no change would be required to the Fatigue Monitoring Program limits. If the number of cycles for the design transient had to be reduced due to lower allowable cycles to obtain a CUF value less than 1.0, this reduced number of cycles would become the new Fatigue Monitoring Program cycle limit.

An additional clarification is that the piping design code of record is USAS B31.1 (as opposed to ANSI B31.1, which had been used interchangeably in the application).

<u>RAI Clarification J:</u>

The LRA stated that one of the replacement connections used a saddle-shaped reinforcement plate, and the other five were replaced using a pad plate reinforcement. In its response to the RAI, The applicant indicated that only the three connections downstream of the motor-driven AFW pumps were replaced with the thermal sleeve design in the early 1970's. There is an apparent inconsistency between the two. This is defined as open item 4.3.2-1.

The LRA reported that "The saddle configuration was later determined to result in considerably more fatigue than the pad plate configuration, and it was replaced with a pad plate reinforcement design in 1995. In conjunction with that modification a fatigue calculation was performed for this feedwater branch connection reinforcement plate. This analysis is considered to be a TLAA." In its response to the RAI, the applicant stated that during the license renewal review of this fatigue analysis, an error was discovered, and the analysis was revised. Whether it was a design modification or a correction of error need to be clarified as part of the resolution of open item 4.3.2-1. The resulting CUF from the revised fatigue calculation was 0.99 based upon a reduced number of postulated design transients and SDAFW pump surveillance tests. These postulated numbers of transients are being incorporated as limits in the FMP. The staff finds that CUF of 0.99 for 40-year life does not justify the RAI response that "At the current rates of occurrence, the limits would be reached at approximately year 50...." This shall also be clarified as part of the resolution of open item 4.3.2-1. Since the reduced numbers of transients is less than the 60-year projected cycles, additional actions may be required for these components for the period of extended operation. Prior to exceeding the reduced transient limits, the components will either be re-analyzed or replaced. The FMP will be updated to reflect changes in the design basis, when appropriate.

In response to part iii) of the RAI, the applicant performed reviews during the RNP Integrated Plant Assessment and found no nonstandard components used in safety systems, including each type of AFW/FW connection, on the basis that the designs meet the ANSI B31.1 requirements. The staff disagrees with this assessment since the fatigue analysis, considered as a TLAA, was performed to the requirements of ASME Section III Code. This also needs to be resolved as part of open item 4.3.2-1.

The current ISI Program at RNP already includes each of the critical welds for the surge line, which directly examines the limiting component in the plant (the hot leg nozzle). The three welds on the other end of the surge line near the pressurizer surge nozzle are also examined. Each of these locations has been examined during the current operating period, and no unacceptable indications were present. Further examinations are required at least once during each 10-year ISI interval thereafter. The frequency of inspections is specified by Section XI requirements. The staff finds the justification on the inspection interval inadequate to demonstrate that the examinations at the 10-year

interval will prevent any crack from becoming unstable before the next inspection. The completed EAF-adjusted environmental fatigue analysis calculated a CUF of 14.7 for a 40-year plant life at the limiting location using current methodology. This could be interpreted to mean that, using the same methodology, additional fatigue usage factor of 3.7 could be accumulated during the 10-year inspection interval. This is defined as open item 4.3.2-2. Although the applicant further stated that suitable analyses will be prepared prior to the period of extended operation to demonstrate that a postulated fatigue crack will not grow sufficiently during the inspection interval to exceed the critical flaw size associated with unstable growth, the resolution of this open item is pending on the applicant to provide additional analytical justification on the inspection interval.

Supplemental RAI Response J:

J.1 Response related to RAI 4.3-7

The following replaces the original RNP Response to RAI 4.3-7.

At RNP, there are three 4 inch-to-16 inch AFW-to-FW connections downstream of the motor-driven AFW pumps and three 4 inch-to-16 inch AFW-to-FW connections downstream of the steam-driven AFW pump. These connections were designed in accordance with USAS B31.1 requirements, and consist of branch piping welded directly to run piping with a supplemental reinforcement plate. Five of the six used a pad plate design, which is affixed over the run pipe, and one used a saddle plate design, which also extended a short distance up the branch line in addition to covering a portion of the run pipe. The saddle plate design was installed downstream of the steam-driven pump.

A leak developed in one of the connections downstream of the motor-driven AFW pumps within the first two years of service and this was attributed to fatigue due the number of thermal cycles imposed by operation and testing. Therefore, the three connections downstream from the motor-driven pumps were replaced with a better design employing a thermal sleeve, also designed to USAS B31.1 requirements, including consideration of thermal cycles. (No ASME Section III fatigue analysis was performed for these connections).

The three 4 inch-to-16 inch AFW-to-FW connections downstream of the steam-driven AFW pump were not replaced due to the relatively low usage of the steam-driven pump. These three original connections included two of the pad plate reinforcing plate design and one with the saddle reinforcing plate design, each designed in accordance with USAS B31.1 design requirements. However, in the early 1990's, due to concerns about possible fatigue problems with these remaining three original connections, more rigorous fatigue analyses were performed for each of these two configurations using methodology from ASME Section III, Class 1 rules. This consisted of an upgraded component qualification method, but was not a design change. The analyses showed

that the saddle plate design was inferior to the pad plate design, and a modification was performed which removed the saddle reinforcement plate on the one connection, and replaced it with a pad-type reinforcing plate like the remaining two connections. The ASME Section III fatigue analysis of the pad plate design applies to all three of these connections, and this analysis was determined to be a TLAA for license renewal.

However, during the license renewal review of this fatigue analysis, an error was discovered in the analysis, and the analysis was revised in 2002 to correct the error. The three connections could not be qualified for the full 40-year design transient set, so a reduced number of design transients were postulated that could be qualified. This resulted in a CUF value of 0.99. Based upon projections of actual transients to date, the qualified number of transients is not expected to be reached until approximately year 50 during the period of extended operation.

Fatigue of these connections will be managed by the Fatigue Monitoring Program by incorporating the reduced numbers of transients as limits, as shown in the Response to RAI 4.3-2, Question 1a. The connections will not be allowed to be exposed to more thermal transients than have been analyzed. Prior to this occurring, the components will be reanalyzed, repaired, or replaced. The Fatigue Monitoring Program will be updated to reflect any change in design basis, when appropriate.

Reviews performed during the RNP IPA found no nonstandard components used in safety systems, based upon considering USAS B31.1 as the design code. This includes each type of AFW/FW connection. ASME Code, Section III is not the applicable design code, even though portions of it were used as a basis for preparing the fatigue analyses.

J.2 Response related to RAI 4.3-10

Based upon discussions with the NRC Staff, RNP proposes the following revised response to RAI 4.3-10 and Clarification J:

The fatigue analysis performed in response to NRC Bulletin 88-11 included evaluation of the RCS hot leg nozzle branch connection (where the pressurizer surge line attaches to the RCS hot leg piping) and it was determined to be the limiting location with respect to fatigue within the surge line. The pressurizer surge line (including the RCS hot leg nozzle) was also one of the seven locations identified in NUREG/CR-6260 that was evaluated for EAF. The RCS hot leg nozzle location is considered to be a bounding example representative of the remainder of the pressurizer surge line with respect to EAF.

The EAF-adjusted CUF value for the surge line, including the hot leg nozzle, has not been shown to be below 1.0 based upon current methodology. Further action is required for management of environmental fatigue of the surge line for the period of

extended operation. Therefore, fatigue of the surge line will be managed using one or more of the following options:

1. Further refinement of the fatigue analyses to maintain the EAF-adjusted CUF below 1.0.
2. Repair of the affected locations
3. Replacement of the affected locations
4. Manage the effects of fatigue through the use of an augmented inservice inspection program that has been reviewed and approved by the NRC. This includes periodic surface and volumetric examinations of the limiting locations at inspection intervals to be determined by a method accepted by the NRC. If this option is selected, the scope, qualification, method, and frequency will be provided to the NRC for review and approval prior to the period of extended operation.

As a result of the above response, the final paragraph in LRA Subsection A.3.2.22, Environmentally Assisted Fatigue, is revised to read:

> Further action is required for management of environmental fatigue of the PZR surge line for the period of extended operation. Therefore, fatigue of the PZR surge line will be managed using one or more of the following options:
>
> 1. Further refinement of the fatigue analyses to maintain the EAF-adjusted CUF below 1.0.
> 2. Repair of the affected locations
> 3. Replacement of the affected locations
> 4. Manage the effects of fatigue through the use of an augmented inservice inspection program that has been reviewed and approved by the NRC. This includes periodic surface and volumetric examinations of the limiting locations at inspection intervals to be determined by a method accepted by the NRC. If this option is selected, the scope, qualification, method, and frequency will be provided to the NRC for review and approval prior to the period of extended operation.

RAI Clarification K (RAI 4.5-1):

In response to RAI 4.5-1, the applicant has provided a Table of predicted prestressing values at various times after the initial prestressing of tendons. Normally, these values are estimated up to the end of the current license, and at the end of the extended period of operation (i.e., at 40 years and 60 years). However, the Table provides values at 50 years and 60 years. In this context, I need a clarification of the Table.

Supplemental RAI Response K:

The original tendon design was based on 50 years rather than 40 years. No basis for the 50 year value was provided in the original analysis. Since the original analysis was based on 50 years, there are no prestress values associated with a 40 year life. The period of extended operation only requires the prestress values to be bounding for a 60 year life. As such, the values provided in the table reflect the prestress value from the original analysis at 50 years, and the prestress value for the extended period of operation at 60 years.

RAI Clarification L:

1) LRA Section B.3.7, states that the fire water system is consistent with XI.M27, "Fire Water System," as identified in the GALL report with certain changes. In order for the staff to evaluate the adequacy of the applicant's fire protection program and reach a conclusion that it is consistent with the guidance in GALL, the staff requests the applicant to confirm the following:

a) A 10 year frequency was identified for the UT examination of above ground fire water piping. Provide the basis for using 10 years as a frequency.

2) LRA Section B.3.1 states that the fire protection program is consistent with XI.M26, "Fire Protection," as identified in the GALL report, with certain changes. In order for the staff to evaluate the adequacy of the applicant's fire protection program and reach a conclusion that it is consistent with the guidance in GALL, the staff requests the applicant to confirm the following:

a) The inspection of fire doors will occur on a semi-annual basis augmented with frequent inspections during operator rounds and additional inspections. Inspections likely include inspections for holes in doors, clearances, corrosion, latches, closing mechanisms, etc. Verify that such inspections are performed, and clarify if the inspections for items discussed above are performed during operator rounds or during the semi-annual inspection.

b) The inspection of fire barriers at RNP will be performed every 10 years, rather than the once per refueling cycle as specified in GALL. Clarify how the RNP process for barrier inspection will ensure that the extended duration between inspections will adequately address aging.

Supplemental RAI Response L:

L.1 Response related to B.3.7

1) a) RNP will perform initial testing (full flow testing, internal inspection, or UT) prior to the expiration of the current operating license, and thereafter at a frequency not to exceed 10 years. The actual frequency specified will be based on the results associated with the initial inspections. If these inspections, representative of roughly 40 years of service, show little or no degradation, then a 10 year inspection interval may be justified. If initial inspections show more significant degradation, then the inspection interval will be shortened commensurately. The objective will be to set an inspection interval that ensures that the fire water system will be able to perform its intended functions in the interim.

The 10 year inspection period is generally consistent with NRC Interim Staff Guidance dated January 28, 2002, that states, "the staff is recommending that in addition to an ultrasonic inspection of the fire protection piping before exceeding the current license term, the applicant shall perform ultrasonic inspections immediately after the 50-year service life sprinkler head testing and at 10-year intervals thereafter." RNP acknowledges that the 50 year NFPA sprinkler head service limit may not concisely correspond with 10 years after the current 40 year license period, but submits that the difference is insignificant with regard to the objectives for testing / examination of piping. As a practical matter, since removal of sprinkler heads requires isolation of the associated piping and provides access for interior piping inspections, performing these activities concurrently would minimize fire water system downtime and optimize utilization of plant operations and maintenance resources

L.2 Response related to B.3.1

2) a) GALL Fire Protection Program XI.M26 specifies bi-monthly inspections for fire door clearances and "holes in the skin of the door." RNP takes exception to these criteria in that RNP fire protection procedures require detailed inspections of fire doors on a semi-annual basis. These semi-annual inspections include criteria specific to door type and design, including latches, closures, sill clearances, seals, and general physical condition, as applicable. The scope of these detailed inspections is consistent with the overall inspections described in GALL XI.M26.

RNP fire door inspections were specified on a semi-annual basis in 1980 to address NRC comments during their review of the RNP Fire Protection Program. RNP considers a semi-annual interval to be sufficient to detect and correct age-related degradation prior to loss of function. While instantaneous physical damage to doors and seals may result from being struck while moving materials or equipment, this would be event-driven, not age-related. The same controls used to maintain the materiel condition of the plant during the current license period will continue to identify and correct this type of physical damage during the period of extended operation. Notably, auxiliary operators make regular general area inspections (normally twice a shift), and RNP procedures direct these inspections include checks that fire doors are closed and fire barriers are intact.

2) b) GALL Fire Protection Program XI.M26 specifies "Visual inspection of the fire barrier walls, ceilings, and floors examines any sign of degradation such as cracking, spalling and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates." GALL does not prescribe a frequency for these inspections, but this criterion directly follows a requirement to inspect a minimum percentage of fire barrier penetrations every refueling outage. RNP does perform the required inspections of fire barrier walls, ceilings and floors. The exception RNP takes in this regard is only to clarify that RNP does not inspect a

fixed percentage of these walls, ceilings and floors each cycle. RNP does meet the GALL requirement for inspections of fire barrier penetration seals.

RNP performs inspections of fire barrier walls, floors and ceilings under its Structures Monitoring Program. Under the Structures Monitoring Program, the walls, floors and ceilings that constitute fire barriers are required to be inspected every 10 years. While there is not an explicit requirement regarding breaking the inspection scope down to a minimum percentage at a prescribed frequency, in practice, these walkdowns are performed on an ongoing basis with the cumulative scope of inspections satisfying the 10 year inspection requirement. From a practical perspective, RNP inspects an average of at least 10% annually over a 10 year period to meet the cumulative inspection requirement. The Structures Monitoring Program is credited with managing aging effects of safety related structures, and is suitable for ensuring that fire barrier walls, floors and ceilings meet fire protection functional requirements as well.

RAI Clarification M:

RAI 2.3.1.3-1 (Pressurizer spray head)

Please discuss the role of the pressurizer spray head in post-accident shutdown procedures, particularly in situations involving fire or steam generator tube rupture. Show that the pressurizer spray head does not meet the criteria of 10 CFR 54.4(a) for inclusion in the LRA scope.

The pressurizer spray head contributes to two of the four preferred methods listed in UFSAR 15.6.3.2.1 for primary side depressurization after a steam generator tube rupture. Although the depressurization function of the pressurizer spray head is not in its design basis, depressurization is still relied upon for post-accident operations, and discounting the pressurizer spray head puts more emphasis upon the remaining two methods. The depressurization function is not in the design bases of the remaining methods either. Could this approach lead ultimately lead to reliance upon four methods of unknown or unproven availabilities?

Is the pressurizer spray head used by the auxiliary spray system to transition from hot shutdown to cold shutdown?

Since the pressurizer spray head is connected to safety-related (pressure boundary) piping, its failure (e.g., by clogging) should be considered in terms of any effects it might have upon the safety-related piping and its functions.

RAI 2.3.1.6-1 (Steam generator feedring)

The steam generator feedring is connected to safety-related piping, which carries auxiliary feedwater to the steam generator shell. Its failure (e.g., by clogging or by losing a J-tube) should be considered in terms of any effects it might have upon the safety-related piping and its functions.

One of these effects could be water hammer. The licensee cites an NRC conclusion that water hammer would not be likely to occur if auxiliary feedwater is limited to 400 gpm. What would limit auxiliary feedwater to 400 gpm? For example, consider a total loss of feedwater accident in which there is no failure in the auxiliary feedwater system, and full-rated auxiliary feedwater flow is delivered.

The situation here is a safety-related pipe, delivering auxiliary feedwater through an out-of-scope component (the feedring) into another safety-related component (the steam generator shell). A failure in the feedring could affect safety-related components in upstream and downstream locations. Consider, for example, a rapid shell-side depressurization (e.g., a steam line break or safety valve opening), causing a degraded J-tube to snap off the feedring and impact upon internal steam generator components, or even block steam flow.

Supplemental RAI Response M:

M.1 Response related to RAI 2.3.1.3-1

The basic long-lived passive intended function of the pressurizer and connected RCS components is to provide pressure-retaining boundary. As stated in the original response to the RAI, the Westinghouse Owner's Group confirmed that none of the applicable plants (which includes RNP) rely on the RCS pressure control function of the pressurizer to prevent or mitigate the consequences of design-basis events, and therefore the passive and long-lived components (e.g., spray head) that perform the pressure control function, but do not perform the pressure boundary function, need not be within the scope of license renewal. The NRC concurred with this assessment in their Safety Evaluation, dated October 26, 2000, of the generic technical report.

Since the pressure control function is not in the design bases, the postulated failure of components that affect this function, and are not required to maintain the pressure boundary of the parent component (i.e., the pressurizer), do not meet the scoping requirements of 10 CFR 54.4(a)(1).

In order to determine whether or not the pressurizer spray head meets the scoping requirements of 10 CFR 54.4(a)(2), two types of failures are postulated. The first failure considered is the inability to spray due to clogging. Clogging of the spray head would affect the pressure control function (outside of the scope of license renewal based on the previous discussion), but does not affect the safety related pressure boundary function. The second hypothetical failure is a loose part generated by the spray head. The spray head is attached to a nominal 4" line inside the pressurizer and is slightly larger than the outside diameter of the line. It is considered highly unlikely that the loose part generated (up to and including the entire spray head) could challenge the pressure boundary function of the pressurizer and/or the connected piping. It is also unlikely that the spray head could impact the operation of the surge line (12-RC-2501R-10, 12" Schedule 140). Therefore, the spray head does not meet the scoping requirements of 10 CFR 54.4(a)(2).

The RCS pressure control function has been assessed in relation to the scoping requirements of 10 CFR 54.4(a)(3). RCS pressure control is required as part of 10 CFR 50.48, Fire Protection. Appendix 9.5.1C of the RNP USFAR contains the Post-Fire Safe-Shutdown Analysis Report. On page 9.5.1C-4B, the UFSAR states:

> "The safe shutdown performance goals of Appendix R, Section III.L establish the criteria for defining systems and components requiring protection. These goals are:
>
> (1) Reactivity Control - Insert sufficient negative reactivity to achieve and maintain cold shutdown conditions.

> (2) Reactor Coolant Makeup - Maintain the reactor coolant inventory within the indicating range of the pressurizer level instrumentation, and control reactor coolant system pressure.
>
> (3) Decay Heat Removal - Remove decay heat through cold shutdown.
>
> (4) Process - Provide direct reading of safe shutdown process variables.
>
> (5) Support Functions - Provide electrical power, cooling, etc., as required to achieve all of the above performance goals."

Controlling reactor coolant system pressure is part of goal (2).

On page 9.5.1C-11 it states:

> "The pressurizer PORVs will be immediately deactivated to the closed position and only the mechanically-operated relief valves to the pressurizer relief tank will be available for primary system pressure relief."

The spray lines are not credited in this scenario and the Appendix R and Station Blackout Safe-Shutdown Analysis Flowpath/Boundary Diagrams do not depict the spray lines as one of the Safe-Shutdown Analysis flowpaths.

Therefore, this component does not meet the scoping requirements of 10 CFR 54.4(a)(3).

In conclusion, since the pressurizer spray head does not meet the scoping requirements 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3), it is not within the scope of license renewal.

<u>M.2 Response related to RAI 2.3.1.6-1</u>

The steam generator is a safety related component that has an overall pressure boundary intended function. Individual subcomponents of the steam generator have additional component intended functions that support the overall pressure boundary intended function (Table 2.3-1 of RNP LRA).

The feedring is not part of the pressure boundary of the steam generator. Therefore, this component does not meet the scoping requirements of 10 CFR 54.4(a)(1).

The steam generator feedring is not connected to safety related piping. The feedring is an internal component of the safety related steam generator. The delivery of sufficient flow to the steam generators to ensure proper water inventory does not require the normal flow distribution capabilities of the feedring.

Per Table 10.4.6-1 of the RNP UFSAR, each of 2 feedwater pumps has a design capacity of 12,700 gpm. Therefore, normal feedwater flow to a steam generator based on 2 pumps feeding 3 steam generators is approximately 8500 gpm. In reviewing Table 15.0.8-1 of the UFSAR, "Component Capacities and Setpoints Used in the Safety Analysis," it is noted that required flow to an individual steam generator is 120 gpm. It is highly unlikely that any credible age-related degradation of the feedring would limit its capacity to deliver less than 2% of the rated flow.

Each of the 2 motor-driven AFW pumps are limited by flow control valves to 325 gpm, and the steam-driven AFW pump is limited to 630 gpm. Therefore, flowrates to individual steam generators would not be expected to reach levels where waterhammer would be expected for the original feedring design. As discussed in the response to the RAI, the new design is less susceptible to waterhammer.

A hypothetical failure of the J-tube is highly unlikely. J-tube inspections of the "B" steam generator were performed during Refueling Outage 16. This inspection also served the purpose of addressing an industry issue with J-tube erosion/corrosion. Feedback from industry contacts showed that the carbon steel portions of the feedring with less than 0.10% chromium content would be susceptible to flow erosion/corrosion. The area susceptible would be on the carbon steel side of the bimetallic weld between the feedring and the J-tube. Samples taken during RO-16 from the "B" steam generator feedring were analyzed and found to be 0.2925% and 0.1298%, which is greater than the limit. In addition, in RO-19, a visual inspection of the steam drum for the "A" steam generator was conducted with no degradation of the J-tubes noted.

Therefore, the feedring does not affect the safety related pressure boundary function of the steam generator and does not meet the scoping requirements of 10 CFR 54.4(a)(2).

Similar levels of AFW flow are required for ATWS, Station Blackout, and an Appendix R fire event. Based on the previous discussion, the RNP AFW system is able to deliver the required flow. The scoping requirements of 10 CFR 54.4(a)(3) are not met for the feedrings.

In conclusion, since the feedring does not meet the scoping requirements 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3), it is not within the scope of license renewal.

RAI Clarification N:

1. RAI 3.4.1-5: Some plants have identified when cooling water was supplied continuously to the oil reservoirs, water was regularly found in the oil. When this was changed so that cooling was supplied only when the pump was running and stopped when the pump was in standby, water was no longer found in the reservoir. Has this been observed at Robinson? Also, is the oil side of the coolers clean, inspected, and tested periodically?

2. RAI 3.4.1-12: If aging effects such as cracking were not managed, how would the structural integrity of the 126 inch diameter concrete circulating water system discharge piping be maintained during a seismic event?

Supplemental RAI Response N:

N.1 Response related to RAI 3.4.1-5

A revised RNP Response to RAI 3.4.1-5 is provided based on comments from internal RNP review and Clarification N:

The initial LRA identified service water (raw water) as the cooling medium for the AFW pump lubricating oil coolers. Raw water is the correct environment for the motor-driven pump oil coolers. However, as noted in the LRA (Table 3.4-2, Item 9), the steam-driven AFW pump is aligned in self-cooling mode. In this mode, the internal environment for the cooler (tube-side) and associated service water piping is treated water (condensate). Therefore, RNP has revised the AMR evaluation to consider the internal environment for the steam-driven pump oil cooler (tube-side) as treated water. This revision to the AMR changed the aging effects identified for the oil cooler, as well as the program(s) assigned to manage the aging effects.

The auxiliary feedwater system pump lubricating oil coolers are closed oil systems. The tube-side environments for these oil coolers are raw water for the motor-driven pumps and treated water for the steam-driven pump. The shell-side of the subject oil coolers is exposed to a lubricating oil environment. The component intended functions for these heat exchangers includes both "heat transfer" and "pressure boundary." Pressure boundary components of these heat exchangers have been evaluated with respect to material and operating environment. The only way for the lube oil side to be contaminated with cooling water is by degradation of the interfacing pressure boundary. Since these heat exchangers have been evaluated for any aging effect that may result in a loss of pressure boundary, the AMR does not need to assume contamination of the lube oil. A review of operating experience did not identify any history of water intrusion for the subject oil coolers. Additionally, if water enters via a leak, oil/water would run out of the (closed) system and be detected during shift operator rounds. Hence, it is event driven and would be repaired upon discovery.

The oil coolers for the motor-driven AFW pumps have been deemed susceptible to age-related degradation on the raw water side of the heat exchangers (tube-side). As identified in LRA Tables 3.4-1 and 3.4-2, these aging effects include flow blockage due to fouling, loss of heat transfer effectiveness due to fouling of heat transfer surfaces, and loss of material due to crevice corrosion, galvanic corrosion, pitting, general corrosion, MIC, and selective leaching. These aging effects are co-managed by the Open Cycle Cooling Water System Program and the Preventive Maintenance Program, as well as the Selective Leaching Program. Assigned PM routing numbers are credited in the Preventive Maintenance Program AMP to manage the identified aging effects. The motor-driven pump oil coolers are cleaned, inspected, and tested on yearly intervals under the RNP Preventive Maintenance Program. The sacrificial anodes are also inspected and replaced, if necessary.

The oil cooler for the steam-driven AFW pump has been deemed susceptible to age-related degradation on the treated water side of the heat exchangers (tube-side). These aging effects include cracking due to SCC, loss of heat transfer effectiveness due to fouling of heat transfer surfaces, and loss of material due to crevice corrosion, galvanic corrosion, pitting, general corrosion, MIC, and selective leaching. These aging effects are co-managed by the Water Chemistry Program and the Preventive Maintenance Program, as well as the Selective Leaching Program. Assigned PM routing numbers are credited in the Preventive Maintenance Program AMP to manage the identified aging effects. The steam-driven pump oil cooler is cleaned, inspected and tested every 18 months under the RNP Preventive Maintenance Program. The sacrificial anode is also inspected and replaced if necessary.

As stated above, the coolers are periodically cleaned, inspected, and tested under the RNP Preventive Maintenance Program. This includes cleaning and inspection of the shell-side (oil) as well as the tube-side. After cleaning and inspection, the coolers are pressure-tested (shell-side). This would identify any degradation of the pressure boundary between the tube-side and shell-side. After re-assembly, the coolers are re-filled with fresh oil and are checked during functional testing. In addition, an oil sample is tested quarterly for the steam-driven AFW pump lube oil cooler and semi-annually for the motor-driven AFW pump oil coolers. A review of laboratory test data dating back to April 1994 supports the OE review. No data were reported that would suggest water intrusion.

<u>N.2 Response related to RAI 3.4.1-12</u>

The portion of the circulating water system within the scope of license renewal is the discharge line extending from the service water discharge connection to the circulating water discharge weir. The 126 inch circulating water discharge piping was designed to AWWA Standard C301 – reinforced concrete water pipe, steel cylinder type, pre-stressed. It is routed from the main condenser seal well to the east side of the Reactor Auxiliary Building, and from there to the discharge weir. It is part of the open loop

cooling system for the main condenser, and is in operation anytime the unit is at power. This non-safety related piping also provides a discharge flow path for service water heat loads from the Reactor Auxiliary Building to the discharge canal. It runs from approximately 6 feet below grade at the service water connection to about 10 feet below grade at the discharge weir. It was conservatively included in license renewal scope on the basis that it constitutes a portion of the discharge flow path from the safety related component cooling water heat exchangers to the circulating water system discharge weir. The only intended function is that it be capable of providing this flow path.

RNP has performed a review to identify aging effects that require aging management for this piping. Since the piping in question is only needed for a service water discharge flow path and is located entirely outside the Reactor Auxiliary Building, the only failure mechanism of concern would be fouling or blockage. While there are many instances of fouling identified in plant and industry operating experience, it is not credible that this 126 inch diameter line could become significantly fouled without being detected on the basis of degraded plant operating conditions. Further, degradation of piping integrity sufficient to impact service water flow is not considered credible based on the following considerations:

- While piping degradation could result in pressure boundary failure and leakage, this would not occlude the piping and therefore not impact the system intended function.
- Based on the relative size of the circulating water piping, a complete structural failure resulting in piping collapse would be necessary to appreciably restrict service water flow. Limited or localized degradation would not result in loss of system intended function.

RAI Clarification O (RAI B.3.14-1):

Open Item 1 (Response to RAI B.3.14-1): Please provide a summary of the results of inspections performed (1) in the below grade sections of the RAB, (2) the submerged portions of the intake structure, and (3) the dam spillway, that would support a conclusion that the below grade structures have not been degraded, and the scope of the enhanced inspection is adequate to detect any significant degradation of the below grade structures during the extended period of operation.

Supplemental RAI Response O:

A summary of the results of inspections performed in the (1) below grade sections of the RAB, (2) submerged portions of the intake structure, and (3) dam spillway, and (4) other below grade concrete are provided below:

(1) Below grade sections of the RAB

A visual inspection of the below grade portion of the RAB foundation approximately three feet deep was performed in July 1999 while the east foundation was exposed during excavation for construction of the north service water header support slab. This general visual inspection monitored for spalling, scaling, erosion, swelling, bulging, signs of corrosion, cracking, settlement, and exposed rebar. In addition, the interior of Manholes 35 and 36, which abut the RAB, were inspected on September 30, 2002. The interior, which had been exposed to groundwater since initial construction, had no signs of spalling or other concrete degradation.

(2) Submerged portion of the Intake Structure

An inspection of the inaccessible areas was performed during Refueling Outage 19 from September 28, 1999, to October 2, 1999, using divers and video equipment. The results of the inspection are as follows. The concrete surface had very little marine growth. There was little or no sediment on the bottom slab. The concrete located at the water line showed signs of erosion from the constant wave action. The top coat of mortar has eroded away leaving the aggregate exposed. The average loss of cover is approximately 1/16" to 1/8". The concrete surface was cleaned of marine growth in a number of locations with a wire brush. The top coat came off with minor effort, thereby exposing the aggregate. Sound material was observed at all cleaned locations. Several repairs were observed to have been made in various locations. One repair had flaked off and rebar was observed (one end cut). The repair material thickness was approximately 2" and the repair area was about one square foot. This area was determined by the Robinson Engineering Section to have no impact on the structural integrity of the concrete. The Structures Monitoring Program will continue to monitor the condition of the normally inaccessible submerged concrete surfaces.

(3) Dam Spillway

An underwater inspection was performed June 20, 2000, by divers. The spillway inspection examined the condition of concrete, especially at the tainter gates. A spalled portion of concrete (6" by 8" by 4" deep) was identified. This area is scheduled to be re-inspected and repaired prior to the period of extended operation. The Dam Inspection Program will monitor the condition of the normally inaccessible submerged spillway concrete surfaces at a frequency not to exceed 10 years. No other underwater concrete degradation was identified.

(4) Other

The interior of eight security manholes were visually examined in August 2002. The interior concrete has been partially submerged from groundwater and provides a similar environment as below grade concrete (exposure to slightly acidic groundwater). No cracking, loss of material, or change in material properties was observed in the concrete surface.

RAI Clarification P:

1. RNP Response to RAI B.3.9-2, page 432 of 504, first paragraph. The applicant stated that "...An impressed current cathodic protection system is credited with protecting the external surface of tank bottoms..." If the cathodic protection system is credited in terms of LRA, the applicant needs to demonstrate that the cathodic system components are qualified as nuclear graded material with stringent NRC requirements. The staff does not believe the cathodic protection systems in the nuclear plants are nuclear grade. The staff believes that the cathodic protection system will be beneficial in protecting buried piping but there is no NRC requirement for the cathodic system to be nuclear graded. Clarify whether the cathodic protection system in RNP is nuclear graded.

2. RNP Response to RAI B.3.12-4B, page 459. The applicant responded to Question B by referencing its response to RAI.B.3.10-10. However, upon examining the applicant's response to RAI B.3.10-10 (do you mean Response to RAI B.3.10-1), the staff is not clear of all the buried pipes that are covered in the buried piping inspection program. Please list the buried pipes in the buried piping inspection program.

3. RNP Response to RAI B.3.8-1. Page 420. (A) Clarify the last paragraph on page 420. The staff assumes that IC Turbine fuel oil storage tanks and EDG fuel oil storage tanks are covered in the buried piping surveillance program. (B) The staff assumes that the 4 pipe lines that the applicant provided on page 420 are a part of the fuel oil system that connects the fuel oil storage tanks for EDG and DSD systems (as shown on page 439, RNP Response to RAI B.3.10-1).

4. RNP Response to RAI B.3.8-5, page 425. Please spell out the following acronyms: AWG, HMWPE, CD (Durichlor).

5. RNP Response to RAI B.3.3-6, page 412. On the graph of predicted pipe thickness vs measured thickness..LCF = 1.540. What is "LCF"?

6. RNP Response to RAI 3.1.2.1-3, pages 143, 144. On top of page 144, the applicant states that loss of pre-load due to stress relaxation is not an aging effect, but on page 143, the applicant states that it uses EPRI guideline on bolting and torque program on bolts. The statements seem to be contradicting each other. Clarify.

Supplemental RAI Response P:

P.1 Response related to RAI B.3.9-2

The cathodic protection system at RNP is classified as non-safety related and, therefore, it is not nuclear grade. The cathodic protection system is credited with

protecting the external surface of the tank bottoms from corrosion. Protection from corrosion is not a safety related or augmented safety function. Therefore, there is no requirement for it to be safety grade.

P.2 Response related to RAI B.3.12-4B

RNP concluded that the requested information is related to RAI B.3.12-1 and not RAI B.3.12-4B.

The details associated with the scope of the Buried Piping Inspection Program are maintained at the site. The Supplemental RAI Response to Clarification A discusses how it can be determined which pipes are buried in the service water and fire protection systems. The RNP Response to RAI B.3.8-1 identifies a few fuel oil pipe line numbers. (The aspects of the fuel oil pipe coatings will be addressed by this inspection program.) Finally, the dedicated shutdown diesel system has two short sections of carbon steel pipe that are buried or encased in concrete outside the dedicated shutdown diesel enclosure. These pipes are the inlet and outlet to the jacket water radiator/tower. The external environment is modeled as buried/damp soil and included in the inspection program.

P.3 Response related to RAI B.3.8-1

(A) The internal combustion turbine fuel oil storage tanks and EDG fuel oil storage tanks are covered in the Above Ground Carbon Steel Tanks Program. This program addresses the external surfaces of the tank. The bottom, external surface of these tanks, which is in contact with the ground, is protected from the loss of material due to corrosion by the cathodic protection system. The Above Ground Carbon Steel Tanks Program evaluation refers to the Buried Piping Surveillance Program as a means for this protection and is used as a compensatory measure to justify an exception in the way GALL addresses an element in the Above Ground Carbon Steel Tanks Program. Since these tanks are not buried and the external bottom surfaces are not accessible for inspection, it is not appropriate for them to be included in the Buried Piping and Tank Surveillance Programs or the Buried Piping and Tank Inspection Programs. The last paragraph was added to the response in an attempt to ensure completeness in the RNP Response to RAI B.3.8-1.

(B) The four pipe lines on page 420 of the April 28, 2003, RAI response are a part of the fuel oil system that connects the fuel oil storage tanks for the EDGs and DSDG. The four pipe lines are shown on the LR boundary drawing G-190204DLR, Sheets 1, 2, and 3. They are part of the piping system that connects the Unit 1 internal combustion turbine tanks to the DSDG fuel oil storage tank (Sheets 1 and 3). They are also part of the fuel oil piping that connects the outside diesel fuel oil storage tank to the EDG day tanks (Sheet 2). One of the small bore underground pipes enters the auxiliary steam boiler "C" shed and supplies fuel to the boiler.

As a result of a recent scoping inspection, it was decided to include the buried 6" pipe from the Unit 1 internal combustion turbine tanks to the DFOST in the evaluation boundary.

P.4 Response related to RAI B.3.8-5

AWG - American Wire Gage

HMWPE - high molecular weight polyethylene (HMWPE) commonly used as a designator for direct burial cable.

Type CD (Durichlor) - Durichlor is an alloy of a high silicon chromium cast iron.

P.5 Response related to RAI B.3.3-6

As identified in the RNP Response to RAI B.3.3-6, the acronym "LCF" stands for "line correction factor." The CHECWORKS model uses plant data, such as water chemistry, flow rates, temperatures, and steam quality to create a model that is specific to RNP. The model is self-correcting, so that actual measured thickness data can be entered and the predicted thickness adjusted based on empirical data. This adjustment method is known as applying the "line correction factor" or "LCF."

P.6 Response related to RAI 3.1.2.1-3

RNP considers that prevention of loss of pre-load is a design problem, and that a properly specified and tensioned fastener will not normally exhibit this phenomenon (i.e., requires no aging management). RNP has developed an effective bolting and torquing program based on EPRI guidance that considers material properties, joint, and gasket design, and service requirements in specifying torque and closure requirements. As stated in the RAI response, loss of pre-load due to stress relaxation "is not an aging effect requiring management" for the applications discussed.

RAI Clarification Q:

1. RNP Response to RAI B.3.9-2, page 432 of 504, first paragraph. The applicant stated that "...An impressed current cathodic protection system is credited with protecting the external surface of tank bottoms..." If the cathodic protection system is credited in terms of LRA, the applicant needs to demonstrate that the cathodic system components are qualified as nuclear graded material with stringent NRC requirements. The staff does not believe the cathodic protection systems in the nuclear plants are nuclear grade. The staff believes that the cathodic protection system will be beneficial in protecting buried piping but there is no NRC requirement for the cathodic system to be nuclear graded. Clarify whether the cathodic protection system in RNP is nuclear graded.

2. RNP Response to RAI B.3.12-4B, page 459. The applicant responded to Part B of the RAI question by referencing its response to RAI.B.3.10-10. However, upon examining the applicant's response to RAI B.3.10-10 (do you mean Response to RAI B.3.10-1), the staff is not clear regarding the identification of all buried pipes that are covered in the buried piping inspection program. Please identify all the buried pipes in the buried piping inspection program.

3. RNP Response to RAI B.3.8-1. Page 420. (A) Clarify the last paragraph on page 420. The staff assumes that IC Turbine fuel oil storage tanks and EDG fuel oil storage tanks are covered in the buried piping surveillance program. (B) The staff assumes that the 4 pipe lines that the applicant provided on page 420 are a part of the fuel oil system that connects the fuel oil storage tanks to the diesel generators in the EDG and DSD systems (as shown on page 439, RNP Response to RAI B.3.10-1).

4. RNP Response to RAI B.3.8-5, page 425. Please spell out the following acronyms: AWG, HMWPE, CD (Durichlor).

5. RNP Response to RAI 3.1.2.1-3, pages 143 and 144. On top of page 144, the applicant states that loss of pre-load due to stress relaxation is not an aging effect, but on page 143, the applicant states that it uses EPRI guideline on bolting and torque program on bolts. The statements on pages 143 and 144 seem to be contradicting to each other. Clarify.

6. RNP Response to RAI 3.1.2.4.6-2 In the RAI, the staff asked whether the applicant will inspect the following steam generator components: steam generator feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetration nozzles, tube bundle wrappers, tubeplate and associated cladding, steam flow limiters, and lower head divider plates. (A) The applicant referenced the One-time Inspection Program in LRA B.4.4. The steam generator related areas that the one-time inspection program covers are feedwater system, auxiliary feedwater system, and steam generator blowdown system. Confirm

that this inspection will cover steam generator feedwater nozzle thermal sleeves. (B) The applicant referenced item 32 in Table 3.1-1 which prescribes inservice inspection for steam generator upper and lower head, tubesheet, and primary nozzles and safe ends. Clarify if this inspection includes steam flow limiters inside of the steam nozzles or steam lines. (C) Clarify whether the following components will be inspected: secondary side manway and handhole covers, secondary side shell penetration nozzles (other than feedwater or steam lines), tube bundle wrappers, and lower head divider plates.

7. RNP Response to RAI B.3.8-2 Part B., Page 422. (A) Spell out the acronym "SFPS." (B) The applicant stated that leak testing is not specified for the service water system because it has a high flow rate and moderate pressure. The staff is not clear the reason for not performing periodic leak testing unless any leak in the SWS piping can be detected readily. (C) The applicant stated that the fluid inventory in the DSD system is monitored periodically. Clarify how often the fluid inventory is monitored.

8. Generic question on buried pipes (Reference: RNP Response to RAI B.3.8-4, page 424.) Describe the coating (e.g., material used) on all the buried piping covered in the buried piping surveillance and inspection program

9. RNP Response to RAI B.3.9-4A. The applicant stated that it will perform walkdown inspection of the above ground tanks. Discuss how often a walkdown is performed.

10. RNP Response to RAI B.3.12-3, page 463, first paragraph, 5th line down. Should the "jacket water system" be "Jockey water system"?

11. RNP Response to RAI B.3.12-4. The applicant did not respond to Parts A, B, and C of the RAI question satisfactorily. As for Part E, the applicant needs to specify the inspection frequency of the cathodic protection system.

12. RNP Response to RAI B.3.12-5. (A) The applicant discussed the potential catastrophic failure based on operating experience with leakage in the service water system (SWS). The staff is not clear whether the experience in SWS is applicable to the buried fuel oil piping because of different fluid medium and pressure conditions. The staff is not clear if a leak in the buried fuel oil piping will be detected readily as in the SWS. Clarify. (B) The applicant did not respond to Part B of the RAI question satisfactorily. The applicant need to show that the operators have been trained and that there are operating procedures and guidance to shutdown the plant safely should a leak or rupture occurred in any of the buried piping. (C) In its response to Part C of the RAI question, the applicant did not assess the potential catastrophic failure of the fuel oil system nor SWS covered under LRA B.3.12. The applicant responded that failure of the SWS is extremely unlikely given the plant operating history. The thrust of the question is not whether the catastrophic failure has a low probability of occurrence, but rather for a given catastrophic pipe failure, what are the operator actions to mitigate the

impact of the pipe failure to assure a safe shutdown. The applicant needs to discuss operating procedures and instructions to mitigate a catastrophic failure of the buried piping. The applicant also needs to discuss the consequence of pipe failure in the SWS and fuel oil system.

Supplemental RAI Response Q:

RAI Clarification Q, questions 1, 2, 3, and 4, are identical to questions 1 through 4 in RAI Clarification P. Clarification question 5 is identical to question 6 in Clarification P. Refer to Clarification P for the supplemental responses for these questions.

Q.6 Response related to RAI 3.1.2.4.6-2

The original RAI was focused on the efficacy of the Water Chemistry Program to manage the aging effects of cracking and loss of material. For the components specified in the RAI, RNP provided specific reference to where these components were evaluated in the LRA. In the final paragraph of the response, RNP referred to RAI 3.4.1-10. The response to this RAI provides the detail as to the efficacy of the Water Chemistry Program to manage the aforementioned aging effects. The One-Time Inspection Program includes the Water Chemistry Program inspections that are used to verify the effectiveness of that program. As noted in the original response, inspections of various systems upstream of the steam generators are used to verify the effectiveness of the Water Chemistry Program.

(A) The feedwater nozzle thermal sleeves are not inspected by the One-Time Inspection Program.

(B) The steam flow limiters are not managed by the Inservice Inspection Program.

(C) The components listed do not credit inspections for aging management and are not inspected to verify the effectiveness of the Water Chemistry Program.

Q.7 Response related to RAI B.3.8-2B

(A) SFPS - Site Fire Protection System.

(B) UFSAR Table 9.2.1-2, "Service Water Design Requirements," shows that normal flow requirements are 23,025 gpm and accident conditions are 15,466 gpm. Therefore, there is a significant flow rate loss that could be sustained before safety is impacted. Certainly, much lower differences will be detected by pooling of water on the surface as demonstrated by site experience, e.g., see RNP Response to RAI B.3.12-2 regarding leakage in the north service water header.

SWS buried piping leakage testing is performed and covered under the IST program. Relief from hydrostatic testing required by ASME Section XI was obtained in Relief Request RR-11. Alternate leakage testing is performed in accordance with IWA-5244. RR-11 was granted in NRC letter from Allen G. Howe, NRC, to J. W. Moyer dated September 26, 2002, "Fourth 10-Year Interval Inservice Inspection Program Plan Requests for Relief (1-17) For H.B. Robinson Steam Electric Plant, Unit 2 (TAC No. MB2773)." It was determined that leakage testing in lieu of hydrostatic testing is acceptable without significant loss of safety.

(C) There is a monthly check of the water level in the dedicated shutdown diesel generator jacket water system expansion tank as part of the check prior to start of the DSDG.

<u>Q.8 Response related to RAI B.3.8-4</u>

Buried SW piping extending from the service water intake to the Reactor Auxiliary Building was originally ordered to coatings specification AWWA-C-205-66. AWWA-C-205-66 pertains to coal tar protective coatings and linings for steel water pipelines.

Coatings on fuel oil system buried piping are taped with coal tar-type. Specific documentation for coating material was not found.

Two sections of dedicated shutdown diesel generator jacket water system piping are buried piping below the concrete slab outside the diesel engine enclosure. No information on coating was found in the available documentation.

Buried fire protection piping was evaluated as carbon steel and cast iron. RNP underground fire protection piping does not have external coatings, however, some piping support components have had a corrosion retardant coating applied in accordance with NFPA-24. The specific coating material was not identified in the documentation. RNP included the fire protection piping in this inspection program to ensure that that it obtains the proper surface inspection whenever it is excavated. Site experience evaluated as part of the license renewal activities has not identified instances of degraded underground fire protection piping.

<u>Q.9 Response related to RAI B.3.3.9-4A</u>

An enhancement to current inspection activities is to externally inspect the carbon steel tanks at a minimum frequency of once every refueling outage.

Q.10 Response related to RAI B.3.12-3

In the subject paragraph, the fire protection jockey pump and the emergency diesel generator jacket cooling water system are in separate systems. In addition, the wording of the last sentence in the paragraph has been changed to clarify that the jacket water level is checked to determine system integrity. The paragraph now reads:

> "A summary-level discussion has been provided in the LRA regarding operating experience. As noted in LRA Section B.3.12, the site operating experience and the high soil resistance are the basis for not performing scheduled inspections. Additionally, service water systems can tolerate some leakage and still achieve their safety function. A jockey pump normally maintains the site fire protection system headers at normal operating pressure. The inability of the jockey pump to maintain header pressure would provide notice of potential leakage in buried piping. Monthly checks of the water level in the dedicated shutdown diesel generator jacket water system expansion tank would reveal the loss of jacket water system integrity and provide a means to detect leakage in DSDG buried piping."

Q.11 Response related to RAI B.3.12-4

(A) NRC Inspection Report 50-261/91-21, dated October 25, 1991, identified finding 91-21-04, Corrosion Protection of Underground Fuel Oil Piping. This finding was closed in 1992 and the closure notes reprinted in the response to B.3.12-3 demonstrated the integrity of the system and that the system was upgraded to operable status. These upgrades are discussed in RNP Response to RAI B.3.8-7 and were designed and installed in accordance with National Association of Corrosion Engineers standards. Therefore, there is reasonable assurance that the system will perform its protective function.

(B) The potential for service-induced coating degradation could be caused by improper operation of the system. The system is operated and maintained in accordance with the appropriate NACE standards as described in the RNP LRA description of the surveillance program B.3.8, Buried Piping and Tanks Surveillance Program, and in the RNP Response to RAI B.3.8-6, part C.

(C) Please refer to the RNP Response to RAI B.3.8-1 for piping components covered by the cathodic protection system. As noted in that response, these fuel oil piping components are composed of carbon steel.

(E) Monitoring and maintenance activities for the cathodic protection system occur monthly and annually, respectively, and are described in more detail in the RNP Response to RAI B.3.8-4.

Q.12 Response related to RAI B.3.12-5

(A) See the RNP Response to B.3.12-2, Part C, for a discussion of fuel oil leaks in buried fuel oil piping.

(B) An Abnormal Operating Procedure specifically addresses loss of the service water system. Operators are trained to respond to loss of a SWS header and how to safely shut down the plant. The operators are trained and procedures written so that the operators can detect which service water header has failed and how to ensure sufficient service water is available through alternate flow paths.

(C) Fuel oil from the diesel fuel oil storage tank can be supplied to either EDG day tank by two redundant, safety-related underground paths. There is a single underground path from Unit 1 to the Unit 2 DSDG fuel oil storage tank, and an independent flowpath to the DFOST. There are at least 3.5 to 4 days of capacity on the DFOST before any additional fuel would be required. Other alternatives for getting fuel oil via truck are available as identified in the UFSAR and Technical Specifications Bases. A system operating procedure addresses operation of the fuel oil system.

The following information provides clarifications resulting from internal review, or from issues raised during meetings or telephone calls.

RAI 2.3.3.15-3 Clarification:

A revised response to RAI 2.3.3.15-3 is provided below based on comments made during an RNP internal review.

Original RAI 2.3.3.15-3:

UFSAR Chapter 9.5.1A, Section 3.7.1.6 discusses the deluge water spray system provided for the hydrogen seal oil unit. UFSAR Section 3.7.2.6 discusses the deluge water spray system provided for the lube oil storage tank. The UFSAR includes discussions in sections 3.7.1.3 and 3.7.2.3 that dedicated shutdown cables are routed outside the turbine building area. Also, the turbine driven auxiliary feedwater pump may be affected in a turbine building fire. The February 28, 1978, SER, Section 5.23, discusses the deluge water spray systems in these areas, "The deluge systems are adequate to control fires in this area." An unmitigated fire in this area may affect the safe shutdown cables described above. Drawing HBR2-8255LR, Sheet 2, indicates that these water suppression systems are not within the license renewal boundary. Either include these deluge water spray systems within the scope of the LRA and perform an AMR or provide the technical basis for their exclusion from scope.

Revised RNP Response:

The cables associated with the DSDG run in conduit along the outside of the turbine building as described in the UFSAR. These cables are important because they are part of the RNP safe shutdown strategy; however, as noted in the UFSAR, for a fire in the turbine building or transformer yard, the motor-driven AFW pumps and normal on-site power distribution system remains available for safe shutdown of the plant. The subject deluge systems were installed as part of the original plant design to protect the plant against oil-type fires, and predated the installation of the DSDG cables. These deluge systems were not designed to protect the DSDG cables (the cables are routed along the southern face of the turbine building structure, outside the deluge areas described in the UFSAR), and are not credited with doing so. Fire protection for the DSDG cables / conduits running along the outside of the turbine building is provided by hose streams from fire hydrants in this area. These hydrants are credited with protecting the DSDG cables, and are within the scope of license renewal.

RAI 2.3.3.15-10 Clarification:

A revised response to RAI 2.3.3.15-10 is provided below based on comments made during an RNP internal review.

Original RAI 2.3.3.15-10:

Flame retardant coatings are discussed in the UFSAR Appendix 9.5.1B, Section D.1.a for areas where redundant safety-related equipment is located, Sections D.2.c, D.3.c related to engineering safeguards cables, Section D.3.e relating to auxiliary building applications, Section D.3.f relating to coating of PVC jacketed cables, and cable coating are also discussed as used in the control room, cable spreading room, emergency switchgear room. Appendix 9.5.1B is described as the fire protection program per Appendix A to BTP 9.5-1. The February 28, 1978 SER, Section 4.8, states that PVC insulated cables in critical areas will be coated with a flame retardant coating and that silicone rubber insulated cables inside containment areas will be coated with a flame retardant coating. The LRA, Section 4.4.1.43 indicates that PVC cables are still relied upon at the plant. 10 CFR 50.48, Section (b)(1)(i) references Appendix A to BTP 9.5-1 SERs for plant's of this vintage. Flame retardant cable coatings could not be identified in the LRA. Include fire retardant cable coatings within scope of license renewal and perform an AMR or provide the technical basis for its exclusion from scope.

Revised RNP Response:

Flame retardant coatings described in UFSAR Appendix 9.5.1B have been added to the license renewal scope. A flame retardant coating was not applied to the silicone rubber insulated cable inside the containment at the cable penetration area. A water suppression system was installed as an alternative. This was proposed to the NRC in a letter dated January 28, 1980, from E. E. Utley to Mr. A. Schwencer. It was found to be acceptable to the NRC as stated in a letter from Steven R. Varga to Mr. J. A. Jones, dated December 8, 1980.

The RNP AMR has been updated to evaluate flame retardant coatings. "Loss of material due to flaking" was identified as an aging effect/mechanism for the flame retardant coatings within the scope of license renewal. The Preventive Maintenance AMP has been revised to manage the aging effect for these components.

RAI 3.1.2.1-9 and RAI 3.1.2.4.1-3 Clarification:

In a meeting with the NRC staff on May 20, 2003, a request was made to provide further justification for the RNP position regarding general corrosion of carbon steel piping components exposed to a wetted external environment. The affected RAIs are RAI 3.1.2.1-6 and RAI 3.1.2.4.1-3.

Supplemental RNP Response:

The following supplements the first paragraph of the responses to RAI 3.1.2.1-6 and RAI 3.1.2.4.1-3.

The RNP AMR methodology considers general corrosion as a potential aging effect for carbon steel piping components exposed to a wetted external environment. For the external surfaces of the subject components to be susceptible to general corrosion, it would be necessary for condensation to be present on the component surfaces. This would require the internal fluid temperature to be less than the dew point of the ambient air. These environmental conditions do not exist under normal operating conditions for the subject carbon steel components. Accordingly, the RNP Aging Management Review did not identify loss of material due to general corrosion as an aging effect for the external surfaces of these components. This is consistent with GALL Section IV, which also does not identify this aging effect for external carbon steel surfaces. (RAI 3.1.2.1-6 refers to V.E.1-b of GALL Volume 2, which is applicable to ESF carbon steel piping.)

RAI 3.1.2.1-9 Clarification:

The following is provided in response to issues raised in a May 21, 2003 conference call between CP&L and NRC.

In the subject teleconference, the NRC expressed concern that the RNP PWR Vessel Internals Program (Subsection B.4.3 in the RNP LRA) may not capture all subcomponents of the internals that may be subject to loss of fracture toughness.

To address this concern, RNP has rewritten its commitments related to this program. The commitments were revised in response to RAI B.4.3-2. RNP will submit, for review and approval, its inspection plan for the PWR Vessel Internals Program 24 months prior to the augmented inspection. This schedule is based on RNP participation in industry initiatives.

RAI 3.1.2.2.4-1 Clarification:

The following is provided in response to issues raised in a May 21, 2003, conference call between CP&L and NRC.

In the subject teleconference, the NRC expressed concern in that RNP did not credit its Section XI Program with regard to inspection of 4" and under Class 1 piping. RNP does perform required Section XI examinations on 4" and under Class 1 piping, with limited exceptions as approved by the NRC. While these exams are not credited with aging management of internally initiated cracking, they do provide ongoing assurance that externally initiated cracking is not manifest, and thereby support the conclusions of the RNP aging management review.

RAI 3.1.2.4.6-4 Clarification:

The following revised response to RAI 3.1.2.4.6-4 is provided due to comments generated during internal review.

RAI 3.1.2.4.6-4:

In the discussion section of AMR Item 12 of Table 3.1-2 of the LRA, CP&L concludes that stress corrosion cracking is not an applicable aging effect for the SG secondary side manway and handhole bolting materials because the minimum yield strength for the bolting materials was less than 150 ksi. The staff needs to emphasize that minimum yield strength refers to a minimum acceptance criteria for the yield strength of a given material (which is a material property) and does not refer to the yield strengths for the materials themselves. The staff has used 150 ksi as the threshold for initiation of SCC in high strength bolting materials (such as martensitic stainless steel grades or precipitation hardened stainless steel grades). The staff considers that SCC will not be an applicable aging effect for high strength bolting materials if the yield strengths for the materials are confirmed to be lower than 150 ksi or the hardness values for the materials are confirmed to be less than a value of 32 on a Rockwell-C hardness scale. In order to take credit that the SCC is not an applicable aging effect for the SG secondary side manway and handhole bolting materials, confirm that either the yield strengths or Rockwell-C hardness values for the SG secondary manway and handhole bolting materials are within the specified acceptable range for the corresponding material property.

Revised RNP Response:

The RNP SG secondary manway and handhole bolting is SA-193 Grade B7.

A survey of industry experience, technical literature, and laboratory corrosion studies (EPRI NP-5769, Volume 2, Figure 11B-1, and NUREG-1339) indicates that SCC should not be a concern for closure bolting in nuclear power plant applications if the specified minimum yield strength is less than150 ksi.

For low alloy, quenched and tempered steel used for closure bolting (SA-193 Grade B7), susceptibility to SCC is avoided by minimum tempering temperature limits. SA-193 specifies a minimum yield strength of 105 ksi for Grade B7 material, but also specifies a minimum tempering temperature. The minimum tempering temperature specified in SA-193 for Grade B7 material is 1100°F. This limits the yield strength to less than150 ksi (threshold for SCC susceptibility) for the subject bolting. This is based upon industry published data which correlates mechanical properties to tempering temperature for the Grade B7 materials. This is supported by the actual certified test report supplied with

the replacement secondary manway bolting at RNP. The replacement bolting was tempered at 1110°F, and the actual yield strengths were found to be less than 127 ksi.

Therefore, cracking due to SCC is not considered to be an aging effect requiring management for the SG secondary manway and handhole bolting.

RAI 3.5.1-8 Clarification:

The following is a revised response to RAI 3.5.1-8 based on issues raised in an e-mail from Mr. David Jeng, NRC.

Original RAI 3.5.1-8:

Table 3.5-1, Item 16, although lists RNP's Structures Monitoring Program (SMP) under the aging management program (AMP) column of the table, states in the discussion that the AMR concluded that above-grade concrete/grout structures have no aging effects. The same discussion makes reference to Item 10 of Table 3.5-2, which, in turn, indicates that no AMP is required. Table 3.5-1, Item 20 states that no aging effects are applicable to masonry walls, although, it lists masonry wall program as its AMP. Table 3.5-2, Item 10 states that reinforced concrete and grout, including concrete sump, in the environment of containment air, indoor-not air conditioned, and outdoor, would experience no aging effects requiring management. Considering the vulnerability of concrete structural components, including masonry blocks and grouts, the staff has required previous license renewal applicants to implement an aging management program to manage the aging of these components. The staff position is that cracking, loss of material, and change in material properties are plausible and applicable aging effects for concrete components inside containment as well as for other structures outside containment. For inaccessible concrete components, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive; however, for all other concrete components, the staff believes an inspection through an aging management program is required. Please confirm that RNP will credit appropriate aging management program(s) to manage the aging effects consistent with the staff position for concrete, masonry blocks, and grout.

Revised RNP Response:

The letter from J. Moyer (CP&L) to NRC, Serial: RNP-RA/02-0159: "Supplement to Application for Renewal of Operating License," dated October 23, 2002, addresses aging management of concrete components. RNP committed to an aging management program for monitoring accessible concrete based on Interim Staff Guidance, and agreed to credit the Structures Monitoring Program and the Dam Inspection Program for examination of accessible concrete. The Component/Commodity Group of "Reinforced Concrete" or "Concrete Tank Foundation" includes grout. Masonry block walls were not specifically identified in the October 23, 2002, letter. However, the Structures Monitoring Program is credited for monitoring the masonry block walls.

LRA Table 3.5.1, Item 16, should state that based on Interim Staff Guidance, the Structures Monitoring Program will be used to monitor accessible concrete.

LRA Table 3.5-2, Item 10, should be deleted.

LRA Table 3.5.1, Item 20, should state that based on Interim Staff Guidance, the Structures Monitoring Program will be used to monitor accessible masonry walls. Based on GALL XI.S5, the Structures Monitoring Program will be used for the aging management of masonry walls.

In addition, the Structures Monitoring Program will be used for aging management of the steel components listed in LRA Table 3.5.1, Item 16. The stainless steel liner components in Group 7 and 8 Structures are addressed in LRA Table 3.5-1, Item 24.

RAI 4.3-8 Clarification:

At a meeting with the NRC staff on May 20, 2003, a request was made to clarify the RNP Response to RAI 4.3-8 as follows:

1. Provide the basis for the primary sampling evaluation determination that the 60-year fatigue usage for the line is acceptable.

2. Specify the particular Section VIII reference that specifies the maximum allowable stress used in determining the maximum loads.

Supplemental RNP Response:

1. The primary sampling piping is no longer used for sampling, but instead, samples are obtained using the letdown line. Therefore, no additional thermal cycles are accumulating, and the number of thermal cycles projected for 60 years was determined not to exceed the B31.1 cycle limits.

2. Section VIII, Section UG-23(c), requirements state that the loads shall not induce a combined maximum primary membrane stress plus primary bending stress across the thickness which exceeds 1.5 times the maximum allowable stress values in tension from the Tables in Subsection C. From Section VIII, Section UG-23(a), the maximum allowable tensile stress values permitted for different materials are given in the following tables, which are included in Subsection C.

Table UCS-23, Maximum Allowable Stress Values in Tension for Carbon and Low-Alloy Steel

Table UNF-23, Maximum Allowable Stress Values in Tension for Nonferrous Metals

Table UHA-23, Maximum Allowable Stress Values in Tension for High Alloy Steel, etc.

RAI 4.3-9 Clarification:

At a meeting with the NRC staff on May 20, 2003, the staff questioned whether the EAF-adjusted CUF values provided in the RNP Response to RAI 4.3-9 valid for 40 years or 60 years.

Supplemental RNP Response:

The original 40-year CUF values have been demonstrated to be conservative for 60 years through projections of actual transients to date. Therefore, these original CUF values also represent 60-year CUF values (without consideration of environmental effects). When this number is multiplied by the F_{en} multiplier, it represents a 60-year EAF-adjusted CUF value. The following table from the RNP Response to RAI 4.3-9 has been labeled and Note 4 added for clarification.

60-Year Environmental Fatigue Projections

LOCATION	Original CUF [4]	F_{en} Multiplier	EAF-Adjusted CUF [4]
1. RPV shell at core support pads	0.229	2.23	0.512
2. RPV outlet nozzle	0.586 [1]	1.70	0.997
3. RPV inlet nozzle	0.370	2.41	0.893
4. Pressurizer Surge Line	0.96 [2]	15.35 [3]	14.7
5. Charging nozzle	0.031	15.35 [3]	0.468
6. Safety injection nozzle	0.046	15.35 [3]	0.699
7. RHR tee	0.022	15.35 [3]	0.334

NOTES 1-3 (no change – see RAI 4.3-9)

NOTE 4: The original CUF values were determined for 40 years. They have also been shown to be conservative for 60 years by projecting actual cycles to date. Therefore, the EAF-adjusted CUF values are valid for 60 years of operation.

RAI 4.6.3-2 Clarification:

Based on a telephone conversation between RNP and the NRC on June 10, 2003, it was agreed that concerns regarding RAI 4.6.3-2 would be carried as a confirmatory item in the Safety Evaluation Report.

RAI B.2.8-2 Clarification:

A revised response to RAI B.2.8-2 is provided below based on comments made during an RNP internal review.

Original RAI B.2.8-2:

In the applicant's Operating Experience program attribute, it is stated that it identified two incore neutron flux thimble tube leakage events. However, the applicant did not describe these events. Please discuss how this operating experience has been incorporated into the detection of Aging Effects, Monitoring and Trending, and Acceptance Criteria program attributes for the Flux Thimble Eddy Current Inspection Program, as supplemented with the additional information provided in the CP&L response to NRC Bulletin 88-09, dated February 8, 1991.

Revised RNP Response:

The two documented tube leaks were discovered at RNP in tubes F-13 and J-07 during 1996 and 1999, respectively. The leakage from F-13 was discovered when RCS coolant was found in the associated tubes during eddy current testing, and the leakage in J-07 was found after an annunciator activated from water accumulating on the seal table from the slow leak.

Initial eddy current testing of F-13 indicated 87% wear-through in the vicinity of the fuel assembly bottom nozzle. Subsequent traces were performed on F-13 and the final ECT report concluded that there was no detectable degradation. This was determined to be an isolated event and not indicative of any general degraded condition for the flux thimbles and not indicative of any degradation associated with fretting. Tube F-13 was capped and removed from service. Tube F-13 has since been replaced and is back in service.

An actual cause and type of failure for thimble tube J-07 could not be determined. Annunciation of an active leak at 100% power resulted in a containment entry to locate the leaking thimble tube and isolate it. J-07 was replaced in RO-20 and the damaged thimble tube was not inspected. Based on the relatively low leak rate of 10 cc/hr, the leakage was attributed to a propagated microscopic through-wall crack. This was also considered an isolated event and not indicative of any general degraded condition for the flux thimbles and not indicative of any degradation associated with fretting.

Because the identified operating experience was not associated with thimble tube wear, no changes were required to the Flux Thimble Aging Management Program. The Flux Thimble Eddy Current Inspection Procedure was revised to note the status of the

various isolated or capped tubes, and to caution inspectors to take necessary precautions when inserting probes into tubes previously identified as leaking.

RAI B.2.8-3 Clarification:

A revised response to RAI B.2.8-3 is provided below based on comments made during an RNP internal review.

Original RAI B.2.8-3:

To ensure that the UFSAR supplement description for the Flux Thimble Eddy Current Inspection Program is cross-referenced to the CP&L response to NRC Bulletin 88-09, amend the UFSAR supplement description for the Flux Thimble Eddy Current Inspection Program to reflect that the information provided in the CP&L response to Bulletin 88-09, dated February 8, 1991, provides additional details regarding the frequency of examinations to be performed, the acceptance criteria for evaluating any flaws that may be detected, and inspection methodology to be used for the examinations.

RNP Response:

The RNP UFSAR Supplement Section A.3.1.8 description of the Flux Thimble Eddy Current Inspection Program (paragraph) will be appended with the following:

> Details regarding examination frequency, flaw acceptance criteria, and inspection methodology are provided in a letter from G. Vaughn (CP&L) to NRC, Serial NLS-91-024, "Response to NRC Bulletin No. 88-09," dated February 8, 1991.

Subsequently, the letter from R. L. Warden (CP&L) to NRC, Serial RNP-RA/99-0019, "Supplemental Response to NRC Bulletin No. 88-09," dated February 20, 1999, provided inspection results and requested the following change in inspection schedule:

> "Eddy current inspections were established to detect wear of thimbles due to localized erosion caused by the vibration of the thimble and physical interaction with reactor internal materials. During the last three inspections covering six (6) operating cycles, no detectable wear has been identified. As a result, CP&L will be postponing the Refueling Outage 19 eddy current inspection of thimble tubes to Refueling Outage 20."

The above request was accepted by NRC letter from R. Subbaratnam (NRC) to CP&L, "H. B. Robinson Steam Electric Plant, Unit NO. 2 (HBRSEP2) -Thimble Tube Thinning In Westinghouse Reactors - Close Out of TAC NO. MA4636," dated January 27, 2000. The January 27, 2000, NRC response indicated that the deferral of the planned inspections was reasonable, and to keep the NRC updated on the results of the thimble

tube inspection program and the results of the RO-20 inspection.

Letter from C. T. Baucom (Progress Energy) to NRC, Serial RNP-RA/03-0071, "Status Update for NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," dated May 27, 2003, was provided in response to the NRC request for the results of the thimble tube inspection program and the results of the RO-20 inspection. Additionally, the May 27, 2003, Progress Energy letter, based on the existing configuration of the thimbles and the inspection results indicating no detectable degradation of the flux thimble tube inner wall, changed the frequency of eddy current inspections from every other refueling outage to every third refueling outage.

RAI B.3.6-1 Clarification:

A revised response to RAI B.3.6-1 is provided below based on comments made during an RNP internal review.

Original RAI B.3.6-1:

Please provide the specific Service Class (such as CMAA Specification # 70 or # 74) to which the cranes within the scope of license renewal were designed.

Revised RNP Response:

Polar Crane

The original Polar Crane specification did not specify a Service Class. It did, however, require the crane to comply with current local, state, and federal statutes, regulations, and safety codes relative to the design, construction, and operation of the crane. A crane vendor drawing denotes the crane Service Class as "Outside – Class A," which corresponds to the Service Class of EOCI Specification #61 for standby service cranes. EOCI #61, "Specifications for Electric Overhead Traveling Cranes," was the design specification in effect at the time the Polar Crane was designed. The Polar Crane was later considered to be in accordance with CMAA-70.

Spent Fuel Cask Crane

The Spent Fuel Cask Crane load bearing structures and components were designed to meet the requirements of CMAA-70 for Class A1 cranes, which is for standby service cranes.

Turbine Gantry Crane

The original Turbine Gantry Crane specification did not specify a Service Class. It did, however, require the crane to comply with current local, state, and federal statutes, regulations, and safety codes relative to the design, construction, and operation of the crane. A crane vendor drawing denotes the crane Service Class as "Outside – Class A," which corresponds to the Service Class of EOCI Specification #61 for standby service cranes. EOCI #61, "Specifications for Electric Overhead Traveling Cranes," would have been the design specification in effect at the time the Turbine Gantry Crane was designed.

Spent Fuel Bridge Crane

The original Spent Fuel Bridge Crane specification did not specify a Service Class. The original design, fabrication, materials, and erection for the Spent Fuel Bridge Crane were in accordance with the AISC Manual of Steel Construction, 1963 Edition. The Spent Fuel Bridge Crane was later modified to add a hoist inspection platform. The Spent Fuel Bridge Crane structure was reanalyzed and compared to the allowable stresses specified in Westinghouse Specifications in accordance with AISC Manual of Steel Construction, Ninth Edition, and Specifications for Aluminum Structures, Section 1, The Aluminum Association, Washington, DC, First Edition 1986.

RAI B.3.18-2 Clarification:

The following is a revised response to RAI B.3.18-2 based on issues raised during a May 20-21, 2003, meeting between CP&L and NRC.

Original RAI B.3.18-2:

The LRA lists the aging effects that are covered by this program, but does not contain information related to the parameters monitored or inspected, detection of aging effects, monitoring and trending, or acceptance criteria. Please provide the above information for each aging effect that the Preventative Maintenance Program will be used to manage.

Revised RNP Response:

The Preventive Maintenance Program will be used to manage the aging effects listed in the introduction to Section B.3.18 (see LRA page B-66).

Parameters Monitored/Inspected

Surface conditions of systems, structures, and components are monitored primarily through visual inspections/examinations. Inspection intervals take into consideration industry and plant-specific operating experience, and manufacturer's recommendations. In addition to visual inspections, other PM activities include tests, checks (bolting tension), UT Inspections, and leak checks. The Preventive Maintenance Program also credits periodic replacement or refurbishment of certain components, as well as routine cleaning and/or drying of components.

Detection of Aging Effects

Surface conditions of systems, structures, and components are monitored primarily through visual examinations to detect external and internal corrosion or deterioration. In addition to visual examinations, certain aging effects are detected by performing leak checks to identify aging effects such as loss of material, cracking, or changes in material properties and/or performance tests, to ensure no loss heat transfer functions. For some equipment, aging effects are managed by periodic scheduled replacement in lieu of inspection or refurbishment.

Monitoring and Trending

The Preventive Maintenance Program is a condition monitoring program with respect to inspections credited to detect the presence and extent of aging effects, such as loss of material. The Preventive Maintenance Program is also a performance monitoring program in that it is credited to identify aging effects that can be linked directly to a

performance parameter. An example of this would be the identification of heat exchanger fouling by the functional testing of heat exchangers. The inspections, replacements, tests, and sampling activities associated with this program are performed on a specific frequency as required by the specific PM tasks. The results of these PM activities are documented. The components included in the PM program are inspected and/or tested at various frequencies depending on the specific component, the aging effect being managed, and operating experience.

The frequency of preventive maintenance activities that are credited for license renewal may be adjusted provided an engineering evaluation is performed justifying the revised frequency based on plant and industry operating experience.

Acceptance Criteria

Acceptance criteria are provided in the PM tasks or in plant procedures referenced for the PM tasks. Acceptance criteria have been evaluated and are tailored, as necessary, to ensure the applicable aging effects are being effectively managed so that no adverse condition that could interfere with a component intended function exists (or could exist prior to the next scheduled PM).

The following is a summary of Preventive Maintenance activities covered by PM procedures or detailed Work Order instructions:

ACTIVITY CREDITED	AGING EFFECTS
Reactor Coolant System	
Periodically check the tension of RCP A, B and C main flange bolting to ensure that stress relaxation has not occurred, and periodic examination / replacement of RCP seals.	Loss of Pre-load due to Stress Relaxation
Internal inspection of Pressurizer Relief Tank lining every third refueling outage.	Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Aggressive Chemical Attack
Steam Generator	
Inspect the subcomponents associated with the Steam Generator Snubber Reservoir in Snubber-1 through Snubber-12 for age related damage & replace components as required.	Change in Material Properties, Cracking and Loss of Material Due to Various Degradation Mechanisms
Feedwater System	
Inspect FW Heaters 6A/B for possible FAC and erosion.	Loss of Material due to FAC Loss of Material due to Erosion
Auxiliary Feedwater	
Inspect MDAFW Pump packing housing (stuffing box) cooling jacket to ensure no flow blockage or degradation from corrosion.	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC

ACTIVITY CREDITED	AGING EFFECTS
	Loss of Heat Transfer due to Fouling of Heat Transfer Surfaces
Clean and Test Motor-Driven and Steam-Driven AFW Pump Oil Coolers	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC Loss of Heat Transfer due to Fouling of Heat Transfer Surfaces
Condensate System	
Inspect condition of bladder and replace, if needed.	Change in Material Properties due to Elevated Temperature Cracking due to Elevated Temperature
Service Water System	
Periodically remove and replace service water pumps A, B, C and D.	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC
Periodically inspect per service water booster pump A and B pressure boundaries.	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to MIC
Periodically replace the ECCS room coolers, i.e., as a minimum, cooling tubes/coils.	Note: Copper tubing has a site history of short life
Component/Closed Cooling Water System	
UT inspection of piping downstream of Component Cooling Water throttle valves on return piping from the Spent Fuel Pool Heat Exchanger (Pipe 10-AC-152N-41).	Loss of Material due to FAC Loss of Material due to Erosion
Inspect HVH-5A/5B (System 8180) outer surfaces of cooling coils for condition (corrosion, leakage, and fouling).	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces
Diesel Generator System	
Replace flexible hoses/lines on Diesel Generator A and B, as required.	Change in Material Properties, Cracking and Loss of Material Due to Various Degradation Mechanisms
Periodically, blowdown DG Air Start Receiver remove water from receiver and drain piping.	Loss of Material due to General Corrosion
Emergency Diesel air Start Strainers S-33A, S-34A, S-33B & S-34B cleaning and inspection for damage and wear.	Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Cracking due to SCC
Clean and inspect Emergency Diesel Air Start Strainers (S-32A/B and S-35A/B) for damage and wear.	Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Cracking due to SCC

ACTIVITY CREDITED	AGING EFFECTS
Dedicated Shutdown Diesel Generator	
Periodically blowdown the Starting Air Receiver	Cracking due to SCC Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC
Perform a general inspection for leaks/condition of flexible hoses in the following systems: Lube Oil, Jacket Water, Starting Air & Fuel Oil.	Change in Material Properties, Cracking and Loss of Material Due to Various Degradation Mechanisms
Fuel Oil System	
Flexible hoses for Fuel Oil System are addressed under PMs for Other Systems	
EOF/TSC Security Emergency Diesel Gen.	
Inspect flexible hoses and replace as required.	Change in Material Properties, Cracking and Loss of Material Due to Various Degradation Mechanisms
Instrument Air System	
Per PM, inspect for degradation of flexible hose used to make the terminal connections on Air Operators and replace as required.	Change in Material Properties and Cracking due to Elevated Temperature Change in Material Properties and Cracking due to Irradiation Embrittlement
Site Fire Protection System	
Periodically, replace Diesel-Driven Fire Pump and Motor-Driven Fire Pump. Inspect inlet basket strainer.	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC
Emergency Diesel Generator CarDox System	
Replace the flex lines on the emergency diesel CO_2 manifolds.	Corrosion, damage or degradation for any cause.
Fire Protection CO_2 System	
Replace the flex lines on the main and reserve CO_2 manifold.	Corrosion, damage or degradation for any cause.
Halon Supply System	
Replace the flex lines on the main and reserve Halon manifold.	Corrosion, damage or degradation for any cause.
Potable Water System	
Inspect, and if necessary, repair and replace Potable Water (PW) System components located in Cable Spread Room, E1/E2 area and in the Battery Room.	Loss of Material due to General Corrosion Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion
Check for pressure boundary leakage in Valves Piping Fittings. (Valves WD-1728, WD-1723 & IVSW-89)	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to MIC
Visually inspect the Stainless Steel airsides of HVH-1, HVH-2, HVH-3, and HVH-4 tubes for leaks	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion

ACTIVITY CREDITED	AGING EFFECTS
and degradation of the pressure boundary. Visually inspect Housing, and Ductwork for leaks and corrosion.	Loss of Material due to MIC
HVAC Auxiliary Building	
Inspect HVH-6A/B, HVH-7A/B & HVH-8A/B Equipment Frames and Housings, and Heating/Cooling coils for condition (corrosion and leakage).	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to General Corrosion Loss of Material due to MIC
Perform the following: Visually inspect EAC-3 and HC-2 coils for condition and leaks; Visually inspect Filter F-49 equipment frames for degradation and housing for degradation and / or pressure boundary; visually inspect Housing, and Ductwork for degradation, leaks and corrosion; and inspect dampers for damage to housing.	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to General Corrosion Loss of Material due to MIC
Perform the following: Visually inspect Equipment Housing of Filters F-35A, F-35B, F-40A, and F-40B looking for leaks and corrosion or degradation of pressure boundary; Visually inspect system housing and ductwork for leaks, corrosion and degradation; Inspect dampers for damage to housing, e.g., corrosion.	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to General Corrosion Loss of Material due to MIC
HVAC Control Room Area (HVAC)	
Per Surveillance Test inspect AHU-1 housing (drip pan) for corrosion and leaks.	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to MIC
Reactor Auxiliary Building	
Conduct routine monitoring of the cable coatings installed on cable trays within the fire zones that comprise the Auxiliary Building to ensure that no notable loss or degradation of the coating system has occurred.	Loss of Material due to Flaking
Various Electrical Systems	
Perform visual inspections of readily accessible cables and connections not included in the RNP EQ Program.	Embrittlement, cracking, melting, discoloration or swelling leading to reduced insulation resistance or electrical failure

RAI B.4.6 Clarification:

A revised response to AMP B.4.6 is provided below based on comments made during the NRC AMP audit of RNP.

Aging Management Program B.4.6 Supplemental RNP Response:

RNP provides the following information in response to the NRC Aging Management Program audit conducted at RNP on May 28 and 29, 3003. This will serve to demonstrate that the ten (10) program elements of the RNP License Renewal Aging Management Program for Non-EQ Insulated Cables and Connections is consistent with GALL Program X1.E1, "Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements." The RNP Aging Management Program is shown as Attachment 1.

Table 1 below provides an evaluation of each of the 10 program elements delineated in GALL Program X1.E1. The first column labeled "GALL Element" is used to identify whether an entire element is being evaluated or only part of an element. For example, an element number of "3-2" indicates that this is the second part of GALL program element "3." The next column is directly quoted "GALL Text" that is to be evaluated. BWR-related text (as applicable) is ignored. The next column provides the evaluation of the RNP AMP against the "GALL Text" in the previous column. Finally, the last column provides the conclusion on whether that element (or sub-element) is consistent with the GALL report.

TABLE 1
NON-EQ INSULATED CABLES AND CONNECTIONS PROGRAM (XI.E1) EVALUATION

GALL ELEMENT	GALL TEXT	EVALUATION	CONCLUSION
1-1 Scope of Program	"This inspection program applies to accessible electrical cables and connections within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen."	The RNP AMP includes accessible insulated cables and connections installed in structures (i.e., areas) within the scope of license renewal. This program includes cables and connections installed in an adverse, localized environment caused by heat or radiation in the presence of oxygen, and purposely includes other plant areas for conservatism.	This program element is consistent with GALL with no exceptions.

2-1 Preventive Action	"This is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation."	The RNP AMP is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation.	This program element is consistent with GALL with no exceptions.
3-1 Parameter Monitored/ Inspected	"A representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, or surface contamination."	The RNP AMP is a representative sampling program. Accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, swelling, or surface contamination.	This program element is consistent with GALL with no exceptions.
3-2 Parameter Monitored/ Inspected	"The technical basis for the sample selected is to be provided."	The technical basis for the sample selected is provided in the RNP AMP.	This program element is consistent with GALL with no exceptions.
4-2 Detection of Aging Effects	"The first inspection for license renewal is to be completed before the period of extended operation."	Following issuance of a renewed operating license for RNP, the initial inspection will be completed before the end of the initial 40-year license term for RNP (July 31, 2010).	This program element is consistent with GALL with no exceptions.
5-1 Monitoring and Trending	"Trending actions are not included as part of this program because the ability to trend inspection results is limited. Although not a requirement, trending would provide additional information on the rate of degradation."	Trending actions are not part of the RNP AMP. However, trending of discrepancies is performed (as required) in accordance with the RNP Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.	This program element is consistent with GALL with no exceptions.
6-1 Acceptance Criteria	"The accessible cables and connections are to be free from unacceptable, visual indications of surface anomalies, which suggest	The RNP AMP requires that accessible cables and connections be free from unacceptable, visual indications of jacket surface anomalies,	This program element is consistent with GALL with no exceptions.

	that conductor insulation or connection degradation exists. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function."	which suggest that conductor insulation or connection degradation exists. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of license renewal intended function.	
7-1 Corrective Actions	"All unacceptable visual indications of cable and connection jacket surface anomalies are subject to an engineering evaluation. Such an evaluation is to consider the age and operating environment of the component, as well as the severity of the anomaly and whether such an anomaly has previously been correlated to degradation of conductor insulation or connections."	All unacceptable visual indications of cable and connection jacket surface anomalies are subject to an engineering evaluation. This evaluation is to consider the age and operating environment of the component, as well as the severity of the anomaly and whether such an anomaly has previously been correlated to degradation of conductor insulation or connections.	This program element is consistent with GALL with no exceptions.
7-2 Corrective Actions	"Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, or relocation or replacement of the affected cable or connection. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions."	Corrective actions (as required) will be implemented through the RNP Corrective Action Program, and may include, but are not limited to, testing, shielding, or otherwise changing the environment, or relocation or replacement of the affected cable or connection. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible insulated cables and connections. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.	This program element is consistent with GALL with no exceptions.

8-1 Confirmation Process	"As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process."	The RNP Corrective Action Program will verify the effectiveness of corrective actions. The confirmation process is considered an integral part of the Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.	This program element is consistent with GALL with no exceptions.
9-1 Administrative Controls	"As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls."	The RNP AMP is controlled by plant procedures. The administrative control for these procedures is the Document Control Program. The Document Control Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.	This program element is consistent with GALL with no exceptions.
10-1 Operating Experience	"Operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizers or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indicators of degradation."	The RNP AMP is a new program. There is no existing operating experience to validate the effectiveness of this program. The GALL report is based on industry OE through April 2001. Subsequent RNP OE will be captured through the RNP OE review process. The OE review process is fully implemented at RNP and used to improve plant procedures and operating practices. This process will continue throughout the period of extended operation.	This program element is consistent with GALL with no exceptions.

Attachment 1: RNP License Renewal Aging Management Program for Non-EQ Insulated Cables and Connections

The Non-EQ Insulated Cables and Connections Aging Management Program is a condition monitoring program designed to provide reasonable assurance that age-related degradation will not inhibit the intended function of insulated cables and connectors within the scope of license renewal during the period of extended operation. The non-EQ insulated cables and connections managed by this program include those used in power, instrumentation, control, and communication applications. The aging effects managed include embrittlement, discoloration, cracking, swelling, or surface contamination leading to reduced insulation resistance or electrical failure.

Scope

The Non-EQ Insulated Cables and Connections Aging Management Program includes accessible (i.e., able to be approached and easily viewed) insulated cables and connections installed in structures (i.e., areas) within the scope of license renewal. This program includes cables and connections installed in an adverse, localized environment caused by heat or radiation, as well as other plant areas. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the cable or connection.

Preventive Actions

No actions are taken as part of this program to prevent or mitigate aging degradation.

Parameters Monitored or Inspected

A representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, swelling, or surface contamination. Cable and connection jacket surface anomalies are precursor indications of conductor insulation aging degradation from heat or radiation in the presence of oxygen, and may indicate the existence of an adverse localized environment.

Detection of Aging Effects

Accessible insulated cables and connections installed in areas within the scope of license renewal will be inspected at least once every 10 years. Following issuance of a renewed operating license for RNP, the initial inspection will be completed before the end of the initial 40-year license term for RNP (July 31, 2010).

Monitoring and Trending

Trending of discrepancies will be performed as required in accordance with the RNP Corrective Action Program. Corrective action, as described in Chapter 17 of the RNP UFSAR, is implemented by the RNP Quality Assurance (QA) Program in accordance with 10 CFR 50, Appendix B.

Acceptance Criteria

The acceptance criterion is no unacceptable, visual indications of jacket surface anomalies, which would suggest that conductor insulation applicable aging effects may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function.

Corrective Actions

Engineering will perform an evaluation on accessible insulated cables and connections when the acceptance criteria are not met, in order to ensure that the license renewal intended functions will be maintained consistent with the current licensing basis. Such an evaluation is to consider the age and operating environment of the component, as well as the severity of the anomaly and whether such an anomaly has previously been correlated to degradation of conductor insulation or connections. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, relocation or replacement of the affected cable or connection. Corrective actions (as required) will be implemented through the RNP Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible insulated cables and connections.

Confirmation Process

The RNP Corrective Action Program will verify the effectiveness of corrective actions (as required). The confirmation process is considered an integral part of the Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Administrative Controls

This program will be controlled by plant procedures. The administrative control for these procedures is the Document Control Program. The Document Control Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Operating Experience

This is a new program. There is no existing operating experience to validate the effectiveness of this program. The GALL report is based on industry OE through April 2001. Subsequent RNP OE will be captured through the OE review process. The OE review process is fully implemented at RNP and used to improve plant procedures and operating practices. This process will continue throughout the period of extended operation.